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State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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PREFACE

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2010 Quarterly State of the Market Report for PJM: January through March*.

1 PJM Open Access Transmission Tariff (OATT), "Attachment M: PJM Market Monitoring Plan," § IV.A, Sixth Revised Sheet No. 452–452A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M § II(f).

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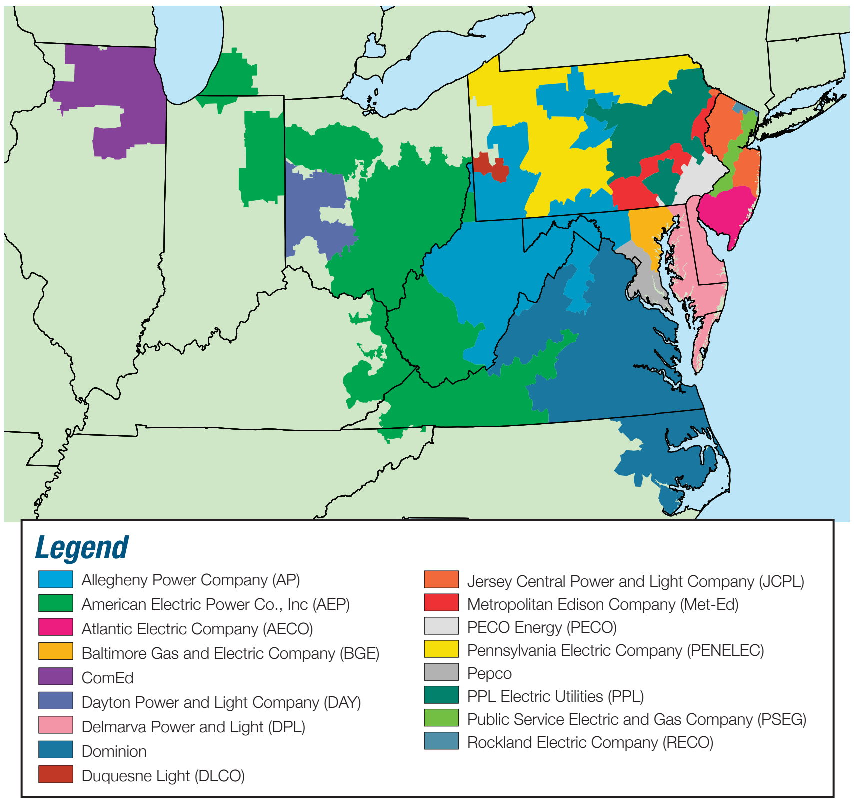
SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of March 31, 2010, had installed generating capacity of 167,795 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including more than 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. (See Figure 1-1.)[1] As part of that function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1-1 PJM's footprint and its 17 control zones (See 2009 SOM, Figure A-1)



1 See the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.

PJM Market Background

PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Markets, the Day Ahead Scheduling Reserve (DASR) Market and the Long Term, Annual and Monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets in mid-1999. PJM implemented an auction-based FTR Market on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the regulation market design and added a market in spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008.[2, 3]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first three months of 2010, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

The MMU concludes that in the first three months of 2010:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;

2 See also the *2009 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

3 Analysis of 2010 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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- The Regulation Market results were not competitive;[4]
- The Synchronized Reserve Market results were competitive;
- The Day Ahead Scheduling Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

Role of MMU in Market Design Recommendations

The PJM Market Monitoring Plan provides under the heading "Market Design," in the section setting forth the MMU's function and responsibilities:

> PJM is responsible for proposing for approval by the Commission, consistent with tariff procedures and applicable law, changes to the design of the PJM Markets. If the Market Monitoring Unit detects a design flaw or other problem with the PJM Markets, the Market Monitoring Unit may initiate and propose, through the appropriate stakeholder processes, changes to the design of such market. In support of this function, the Market Monitoring Unit may engage in discussions with stakeholders, State Commissions, PJM Management, or the PJM Board; participate in PJM stakeholder meetings or working groups regarding market design matters; publish proposals, reports or studies on such market design issues; and make filings with the Commission on market design issues.[5]

In addition, the PJM Market Monitoring Plan provides, in describing MMU Reports: "In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview."[6]

4 The regulation market results are not the result of the offer behavior of market participants, which is competitive as a result of the application of the three pivotal supplier test. The regulation market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher opportunity cost than its owner does.

5 PJM OATT Attachment M § IV.D. On March 18, 2010, PJM filed in Docket No. ER09-1063-000 revisions to Attachment M that, among other things, describe the full scope of this core function, consistent with the Commission's order of December 18, 2009 on PJM's initial filing in compliance with Order No. 719. 125 FERC ¶61,250 at P 113.

6 PJM OATT Attachment M § VI.A.

Recommendations

The MMU recommends retention of key market rules, specific enhancements to those rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets. In this *2010 Quarterly State of the Market Report for PJM: January through March*, the recommendations from the *2009 State of the Market Report for PJM* are still valid, and the MMU has no new recommendations for the first three months of 2010.

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-1 provides the components of the total average price for wholesale power in PJM. Each of these items is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Load Weighted Energy component is the load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments in the first three months of 2010.
- The Transmission Service Charge component is the average price per MWh of network integration charges and firm and non firm point to point transmission service.[7]
- The Operating Reserve (Uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[8]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[9]

7 PJM OATT Section 13.7, Section 14.5 & 27A and Section 34.

8 PJM Operating Agreement Schedules 1-3.2.3 & 1-3.3.3.

9 PJM OATT Schedule 2 and Operating Agreement Schedule 1-3.2.3B.

- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[10]

- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC2) and OATT Schedule 9 funding of FERC, OPSI and the MMU.

- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAILCo and PATH projects.[11]

- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[12]

- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[13]

- The Black Start component is the average cost per MWh of black start service.[14]

- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[15]

- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[16]

- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[17]

- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[18]

10 PJM Operating Agreement Schedules 1-3.2.2, 1-3.2.2A, 1-3.3.2, 1-3.3.2A and OATT Schedule 3.
11 PJM OATT Schedule 12.
12 PJM OATT Schedule 1A.
13 PJM Operating Agreement Schedule 1-3.2.3A.01 and OATT Schedule 6.
14 PJM OATT Schedule 6A.
15 PJM OATT Attachments H-13 and H-14 and Schedule 13.
16 PJM OATT Schedule 10-NERC and OATT Schedule 10-RFC.
17 PJM Operating Agreement Schedule 1-3.6.
18 PJM Operating Agreement Schedule 1-5.3b.

Table 1-1 Total price per MWh: January through March 2010 (See 2009 SOM, Table 1-1)

Category	$/MWh	Percent
Load Weighted Energy	$45.92	73.1%
Capacity	$11.00	17.5%
Transmission Service Charges	$3.87	6.2%
Operating Reserves (Uplift)	$0.63	1.0%
PJM Administrative Fees	$0.38	0.6%
Reactive	$0.35	0.6%
Regulation	$0.34	0.5%
Transmission Enhancement Cost Recovery	$0.12	0.2%
Transmssion Owner (Schedule 1A)	$0.08	0.1%
Synchronized Reserves	$0.05	0.1%
NERC/RFC	$0.02	0.0%
Black Start Services	$0.02	0.0%
RTO Startup and Expansion	$0.01	0.0%
Load Response	$0.01	0.0%
Transmission Facility Charges	$0.00	0.0%
Total	$62.80	100.0%

SECTION 2 – ENERGY MARKET, PART 1

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for January through March of 2010, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2010.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.

1 Analysis of 2010 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

2 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," First Revised Sheet No. 448.05 (Effective June 29, 2009).

Overview

Market Structure

- **Supply.** During the first three months of 2010, the PJM Energy Market received an hourly average of 157,526 MW in supply offers including hydroelectric generation.[3] The January through March 2010 average daily offered supply was 4,994 MW higher than the January through March 2009 average daily offered supply of 152,532 MW. An extended outage at a nuclear power plant in 2009, and increased wind output were the primary causes of the increase.

- **Demand.** The PJM system peak load for January through March 2010 was 101,262 MW in the hour ended 1800 EPT on January 4, 2010, while the PJM peak load for January through March 2009 was 117,169 MW in the hour ended 1800 EPT on January 16, 2009.[4] The January through March 2010 peak load was 15,907 MW, or 13.6 percent, lower than the January through March 2009 peak load.

- **Market Concentration.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Local Market Structure and Offer Capping.** Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier

3 Calculated values shown in Section 2, "Energy Market, Part 1," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

4 For the purpose of the *2010 Quarterly State of the Market Report for PJM: January through March*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2009 State of the Market Report for PJM*, Appendix N, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

test) as the trigger for offer capping in 2010. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours were 0.1 percent in the first three months of 2010, the same level as in 2009. In the Real-Time Energy Market offer-capped unit hours increased from 0.4 percent in 2009 to 0.6 percent in the first three months of 2010.

- **Local Market Structure.** A summary of the results of PJM's application of the three pivotal supplier test is presented for all constraints which occurred for 25 or more hours during the first three months of calendar year 2010. During the first three months of 2010, the AEP, AP, BGE, ComEd, DLCO, Dominion, and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 25 or more hours. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

Market Performance: Markup, Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The LMP impact is a measure of market power. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, as such a full redispatch is practically impossible because it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

  The markup component of the overall PJM real-time, load-weighted, average LMP for the first three months of 2010 was -$0.91 per MWh, or -2.0 percent. Coal steam units contributed -$1.08, or 118.7 percent, to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed $0.11 or -12.5 percent to the total markup component of LMP. The markup was -$0.85 per MWh during peak hours and -$0.97 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP for the first three months of 2010 was -$1.22 per MWh, or -2.5 percent. Coal steam units contributed -$0.91 or 74.5 percent to the total markup component of LMP. Natural gas steam units contributed -$0.31 or 25.0 percent to the total markup component of LMP. The markup was -$0.88 per MWh during peak hours and -$1.56 per MWh during off-peak hours.

  The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** On average, PJM real-time load decreased in the first three months of 2010 by 0.1 percent from the first three months of 2009, falling from 81,174 MW to 81,121 MW. PJM day-ahead load decreased in the first three months of 2010 by 1.1 percent from the first three months of 2009, falling from 94,583 MW to 93,559 MW.

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect the generation fuel mix, the cost of fuel and local price differences caused by congestion.

  PJM Real-Time Energy Market prices decreased in the first three months of 2010 compared to the first three months of 2009. The system simple average LMP was 6.7 percent lower in the first three months of 2010 than in the first three months of 2009, $44.13 per MWh versus $47.29 per MWh. The load-weighted LMP was 7.4 percent lower in the first three months of 2010 than the first three months of 2009, $45.92 per MWh versus $49.60 per MWh. The real-time fuel cost adjusted, load-weighted, average LMP was 8.0 percent higher for the first three months of 2010 than the load-weighted, average LMP for the first three months of 2009, $53.56 per MWh compared to $49.60 per MWh. In other words, if fuel costs for the first three months of 2010 had been the same as the first three months of 2009, the 2010 load-weighted LMP would have been higher, $53.56 per MWh, than the actual $45.92 per MWh, and 8.0 percent higher than the load-weighted average LMP for 2009. Fuel costs and lower loads in 2010 contributed to downward pressure on LMP.

PJM Day-Ahead Energy Market prices decreased in the first three months of 2010 compared to the first three months of 2009. The system simple average LMP was 2.7 percent lower in the first three months of 2010 than in the first three months of 2009, $46.13 per MWh versus $47.41 per MWh. The load-weighted LMP was 3.4 percent lower in the first three months of 2010 than in the first three months of 2009, $47.77 per MWh versus $49.44 per MWh.

- **Load and Spot Market.** Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a PJM parent company that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In the first three months of 2010, 12.6 percent of real-time load was supplied by bilateral contracts, 19.6 percent by spot market purchases and 67.8 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased by 0.3 percentage points; reliance on spot supply increased by 2.6 percentage points; and reliance on self-supply decreased by 2.3 percentage points in 2010.

Demand-Side Response

- **Demand-Side Response (DSR).** Markets require both a supply side and a demand side to function effectively. PJM wholesale market, demand-side programs should be understood as one relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active, well-articulated interaction between wholesale and retail markets.

  If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for an RTO Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior.

  There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. A substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

- **Demand-Side Response Activity.** In the first three months of 2010, in the Economic Program, participation decreased compared to the first three months of 2009. There were decreases in a range of activity metrics including settlements submitted, settled MWh and credits, Participation levels through calendar year 2009 and through the first three months of 2010 are generally lower compared to prior years due to a number of factors, including lower price levels, lower load levels and improved measurement and verification. On the peak load day for the period January through March 2010, January 4, 2010, there were 2,625.0 MW registered in the Economic Load Response Program.

  In the first three months of 2010, the Emergency Program, specifically, the Load Management (LM) Program, participation increased compared to the same period in 2009.[5] Participants in the LM Program are committed RPM resources and participation remains constant through RPM delivery years. For the 2009/2010 delivery year, there were 7,294.3 MW registered in the LM Program, compared to 4498.2 MW registered in the 2008/2009 delivery year.

  Since the introduction of the capacity market on June 1, 2007 the capacity market has been the source of growth in total demand side revenues and demand side revenues from the capacity market were the only significant source of revenue in 2009. In the first three months of 2010, payments from the Economic Program decreased from 2009 by $461,000 or 63 percent, from $731,000 to $270,000 while capacity revenue increased from 2009 by $44 million or 88 percent, from $49 million to $93 million since 2009.

5 The Capacity Only and Full options of the Emergency Program are integrated into RPM through the Load Management Program. The Energy Only option is a voluntary program that does not interact with RPM, however, there are currently no participants registered in this option.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the first three months of 2010, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply increased by about 4,994 MW when comparing the first quarter of 2010 to the first quarter of 2009, while aggregate peak load decreased by 15,907 MW, modifying the general supply demand balance from the first three months of 2009 with a corresponding impact on Energy Market prices. Average load was also lower than in the first three months of 2009. Market concentration levels remained moderate and average markup was negative. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to scarcity conditions. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests.

The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

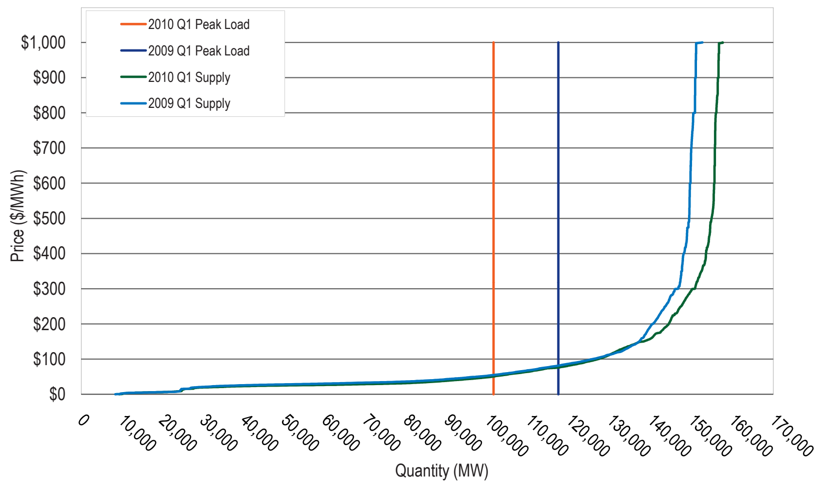
Energy Market results for the first three months of 2010 generally reflected supply-demand fundamentals. Lower prices in the Energy Market were the result of lower fuel costs and of lower demand. PJM Real-Time, load-weighted, average LMP for the first three months of 2010 was $45.92, or 7.4 percent lower than the load-weighted, average LMP for the first three months of 2009, which was $49.60. The real-time fuel cost adjusted, load-weighted, average LMP was 8.0 percent higher for the first three months of 2010 than the load-weighted, average LMP in for the first three months of 2009, $53.56 per MWh compared to $49.60 per MWh. In other words, if fuel costs for the first three months of 2010 had been the same as the first three months of 2009, the 2010 load-weighted LMP would have been higher, $53.56 per MWh, than the actual $45.92 per MWh, and 8.0 percent higher than the load-weighted average LMP for 2009. Lower fuel prices in the first three months of 2010 resulted in lower energy prices in January through March of 2010 than would have occurred if fuel prices had remained at the levels of January through March of 2009. Lower demand also contributed to lower prices.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first three months of 2010.

Market Structure

Supply

Figure 2-1 Average PJM aggregate supply curves: January through March, 2009 and 2010 (See 2009 SOM, Figure 2-1)



Demand

Table 2-1 Actual PJM footprint peak loads: January through March of 2003 to 2010 (See 2009 SOM, Table 2-1)

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)	Difference (%)
2003	Thu, January 23	18	54,670	NA	NA
2004	Mon, January 26	18	53,620	(1,050)	(1.9%)
2005	Tue, January 18	18	96,362	42,742	79.7%
2006	Mon, February 13	19	100,065	3,703	3.8%
2007	Mon, February 05	19	118,800	18,736	18.7%
2008	Thu, January 03	18	111,724	(7,076)	(6.0%)
2009	Fri, January 16	18	117,169	5,445	4.9%
2010	Mon, January 04	18	101,262	(15,907)	(13.6%)

Figure 2-2 Actual PJM footprint peak loads: January through March of 2003 to 2010 (See 2009 SOM, Figure 2-2)

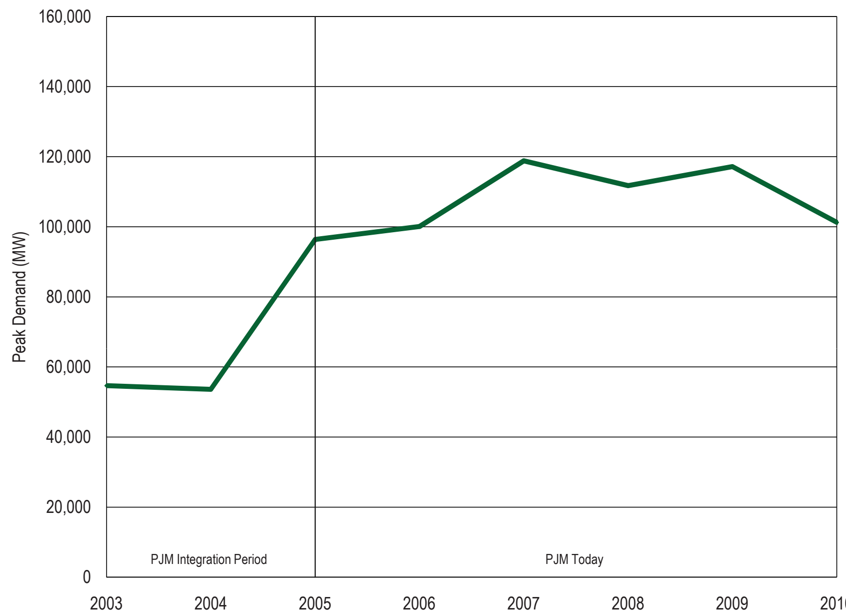
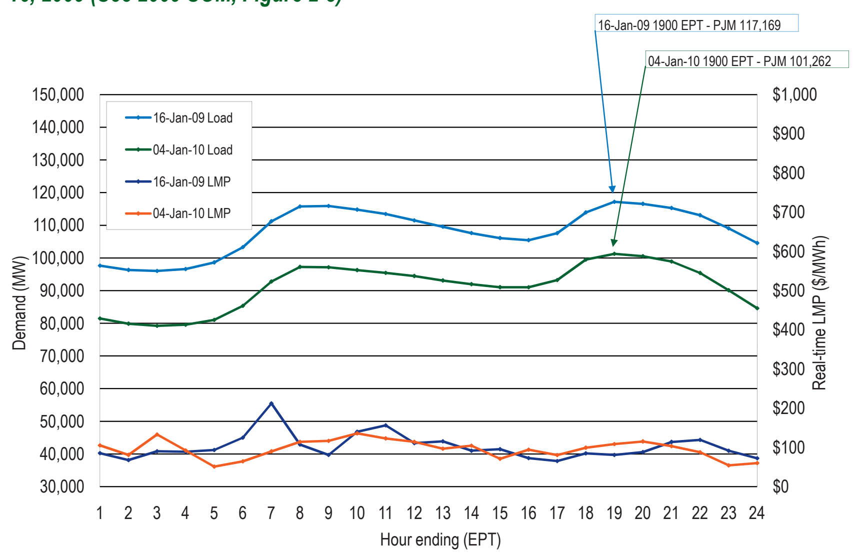


Figure 2-3 PJM 1st quarter peak-load comparison: Monday, January 4, 2010 and Friday, January 16, 2009 (See 2009 SOM, Figure 2-3)



Market Concentration

PJM HHI Results

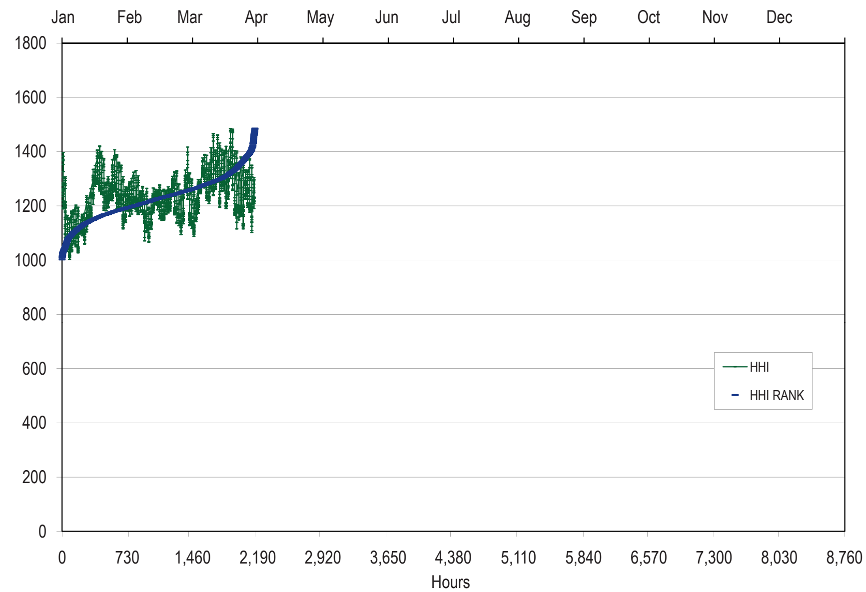
Table 2-2 PJM hourly Energy Market HHI: January through March 2010[6] (See 2009 SOM, Table 2-2)

	Hourly Market HHI
Average	1228
Minimum	1003
Maximum	1485
Highest market share (One hour)	30%
Highest market share (All hours)	21%
# Hours	2160
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Table 2-3 PJM hourly Energy Market HHI (By segment): January through March 2010 (See 2009 SOM, Table 2-3)

	Minimum	Average	Maximum
Base	1118	1258	1462
Intermediate	876	2255	5915
Peak	831	6526	10000

Figure 2-4 PJM hourly Energy Market HHI: January through March 2010 (See 2009 SOM, Figure 2-4)



Local Market Structure and Offer Capping

Table 2-4 Annual real-time offer-capping statistics: Calendar years 2006 through March 2010 (See 2009 SOM, Table 2-4)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2006	1.0%	0.2%	0.4%	0.1%
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	0.6%	0.2%	0.1%	0.0%

6 This analysis includes all hours of the first three months of 2010, regardless of congestion.

Table 2-5 Real-time offer-capped unit statistics: January through March 2010 (See 2009 SOM, Table 2-5)

	2010 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	1	0	28
80% and < 90%	0	0	0	0	0	11
75% and < 80%	1	0	0	0	0	10
70% and < 75%	0	1	0	0	0	1
60% and < 70%	0	0	0	0	0	12
50% and < 60%	0	0	0	0	0	14
25% and < 50%	0	0	0	0	0	23
10% and < 25%	0	0	1	1	1	34

Local Market Structure

Table 2-6 Three pivotal supplier results summary for regional constraints: January through March 2010 (See 2009 SOM, Table 2-6)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	614	525	86%	170	28%
	Off Peak	428	372	87%	109	25%
AP South	Peak	1,756	875	50%	1,269	72%
	Off Peak	1,509	837	55%	970	64%
Bedington - Black Oak	Peak	NA	NA	NA	NA	NA
	Off Peak	21	14	67%	13	62%
Harrison - Pruntytown	Peak	103	92	89%	25	24%
	Off Peak	275	200	73%	130	47%
West	Peak	107	101	94%	9	8%
	Off Peak	43	37	86%	8	19%

Table 2-7 Three pivotal supplier test details for three regional constraints: January through March 2010 (See 2009 SOM, Table 2-7)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	81	294	20	16	3
	Off Peak	57	251	18	15	3
AP South	Peak	78	244	10	4	6
	Off Peak	75	256	10	5	5
Bedington - Black Oak	Peak	NA	NA	NA	NA	NA
	Off Peak	46	133	10	5	4
Harrison - Pruntytown	Peak	68	301	19	17	3
	Off Peak	61	209	17	12	5
West	Peak	124	478	18	17	1
	Off Peak	111	640	22	19	3

Table 2-8 Three pivotal supplier results summary for constraints located in the AEP Control Zone: January through March 2010 (See 2009 SOM, Table 2-12)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Baker - Broadford	Peak	62	17	27%	48	77%
	Off Peak	276	140	51%	210	76%
Cloverdale - Lexington	Peak	93	39	42%	71	76%
	Off Peak	393	152	39%	299	76%
Kanawha River - Kincaid	Peak	145	0	0%	145	100%
	Off Peak	104	0	0%	104	100%
Sullivan	Peak	106	0	0%	106	100%
	Off Peak	25	0	0%	25	100%

Table 2-9 Three pivotal supplier test details for constraints located in the AEP Control Zone: January through March 2010 (See 2009 SOM, Table2-13)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Baker - Broadford	Peak	40	124	9	2	7
	Off Peak	66	215	9	4	6
Cloverdale - Lexington	Peak	78	185	16	6	10
	Off Peak	73	179	14	5	9
Kanawha River - Kincaid	Peak	5	3	1	0	1
	Off Peak	5	3	1	0	1
Sullivan	Peak	22	0	1	0	1
	Off Peak	78	0	1	0	1

Table 2-10 Three pivotal supplier results summary for constraints located in the AP Control Zone: January through March 2010 (See 2009 SOM, Table 2-14)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Doubs	Peak	129	94	73%	45	35%
	Off Peak	13	9	69%	6	46%
Mount Storm - Pruntytown	Peak	1	1	100%	0	0%
	Off Peak	269	148	55%	165	61%
New Martinsville - Paden City	Peak	4	0	0%	4	100%
	Off Peak	NA	NA	NA	NA	NA
Sammis - Wylie Ridge	Peak	24	23	96%	7	29%
	Off Peak	167	105	63%	88	53%
Tiltonsville - Windsor	Peak	511	0	0%	511	100%
	Off Peak	349	0	0%	349	100%

Table 2-11 Three pivotal supplier test details for constraints located in the AP Control Zone: January through March 2010 (See 2009 SOM, Table 2-15)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Doubs	Peak	22	0	14	11	3
	Off Peak	22	25	12	9	3
Mount Storm - Pruntytown	Peak	6	169	7	7	0
	Off Peak	76	233	11	6	5
New Martinsville - Paden City	Peak	3	0	1	0	1
	Off Peak	NA	NA	NA	NA	NA
Sammis - Wylie Ridge	Peak	54	0	17	15	2
	Off Peak	42	97	17	10	7
Tiltonsville - Windsor	Peak	9	2	2	0	2
	Off Peak	7	3	2	0	2

Table 2-12 Three pivotal supplier results summary for constraints located in the BGE Control Zone: January through March 2010 (See 2009 SOM, Table 2-16)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Graceton - Raphael Road	Peak	103	70	68%	58	56%
	Off Peak	28	20	71%	15	54%

Table 2-13 Three pivotal supplier test details for constraints located in the BGE Control Zone: January through March 2010 (See 2009 SOM, Table 2-17)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Graceton - Raphael Road	Peak	53	137	19	11	8
	Off Peak	48	121	18	12	7

Table 2-14 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: January through March 2010 (See 2009 SOM, Table 2-18)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Burnham - Munster	Peak	31	21	68%	10	32%
	Off Peak	406	123	30%	320	79%
Crete - East Frankfurt	Peak	149	7	5%	145	97%
	Off Peak	2,689	52	2%	2,666	99%
Pleasant Valley - Belvidere	Peak	71	0	0%	71	100%
	Off Peak	176	0	0%	176	100%
Waterman - West Dekalb	Peak	187	0	0%	187	100%
	Off Peak	404	0	0	404	100%
Zion - Pleasant Prairie	Peak	261	0	0%	261	100%
	Off Peak	265	0	0	265	100%

Table 2-15 Three pivotal supplier test details for constraints located in the ComEd Control Zone: January through March 2010 (See 2009 SOM, Table 2-19)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burnham - Munster	Peak	25	95	22	15	6
	Off Peak	40	89	13	4	9
Crete - East Frankfurt	Peak	32	130	6	0	5
	Off Peak	34	45	5	0	4
Pleasant Valley - Belvidere	Peak	14	0	1	0	1
	Off Peak	11	0	1	0	1
Waterman - West Dekalb	Peak	8	1	1	0	1
	Off Peak	8	3	1	0	1
Zion - Pleasant Prairie	Peak	57	8	2	0	2
	Off Peak	55	6	2	0	2

Table 2-16 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: January through March 2010 (See 2009 SOM, Table 2-20)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Collier - Elwyn	Peak	174	0	0%	174	100%
	Off Peak	NA	NA	NA	NA	NA
Crescent	Peak	359	0	0%	359	100%
	Off Peak	NA	NA	NA	NA	NA

Table 2-17 Three pivotal supplier test details for constraints located in the DLCO Control Zone: January through March 2010 (See 2009 SOM, Table 2-21)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Collier - Elwyn	Peak	15	16	1	0	1
	Off Peak	NA	NA	NA	NA	NA
Crescent	Peak	24	4	1	0	1
	Off Peak	NA	NA	NA	NA	NA

Table 2-18 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: January through March 2010 (See 2009 SOM, Table 2-22)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Beechwood - Kerr Dam	Peak	83	0	0%	83	100%
	Off Peak	13	0	0%	13	100%
Clover	Peak	107	5	5%	107	100%
	Off Peak	4	0	0%	4	100%
Fredericksburg	Peak	139	0	0%	139	100%
	Off Peak	10	0	0%	10	100%

Table 2-19 Three pivotal supplier test details for constraints located in the Dominion Control Zone: January through March 2010 (See 2009 SOM, Table 2-23)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	5	10	1	0	1
	Off Peak	7	15	1	0	1
Clover	Peak	26	86	5	0	5
	Off Peak	7	0	6	0	6
Fredericksburg	Peak	8	82	1	0	1
	Off Peak	19	53	1	0	1

Table 2-20 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: January through March 2010 (See 2009 SOM, Table 2-30)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Athenia - Saddlebrook	Peak	982	1	0%	982	100%
	Off Peak	319	0	0%	319	100%
Hawthorn - Hinchmans Ave	Peak	60	0	0%	60	100%
	Off Peak	92	0	0%	92	100%
Hawthorn - Waldwick	Peak	80	0	0%	80	100%
	Off Peak	18	0	0%	18	100%

Table 2-21 Three pivotal supplier test details for constraints located in the PSEG Control Zone: January through March 2010 (See 2009 SOM, Table 2-31)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	12	37	2	0	2
	Off Peak	10	35	1	0	1
Hawthorn - Hinchmans Ave	Peak	15	16	2	0	2
	Off Peak	13	12	2	0	2
Hawthorn - Waldwick	Peak	14	15	2	0	2
	Off Peak	14	10	2	0	2

Market Performance: Markup

Real-Time Markup

Ownership of Marginal Resources

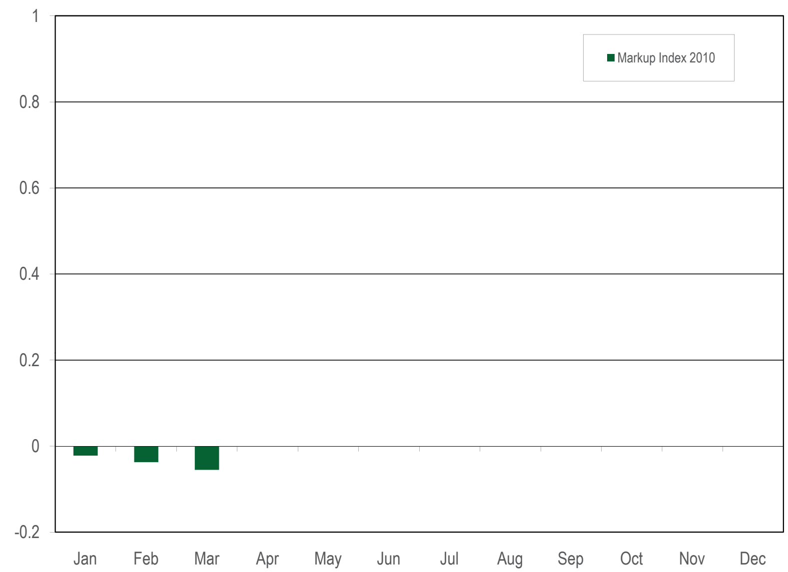
Table 2-22 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through March 2010 (See 2009 SOM, Table 2-32)

Company	Percent of Price
1	21%
2	11%
3	11%
4	6%
5	6%
6	6%
7	4%
8	3%
9	3%
Other (42 companies)	30%

Table 2-23 Type of fuel used (By real-time marginal units): January through March 2010 (See 2009 SOM, Table 2-33)

Fuel Type	2010
Coal	71%
Natural Gas	24%
Wind	3%
Petroleum	1%
Landfill Gas	1%
Misc	0%

Figure 2-5 Real-time load-weighted unit markup index: January through March 2010 (See 2009 SOM, Figure 2-5)



Unit Markup Characteristics

Table 2-24 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through March 2010 (See 2009 SOM, Table 2-34)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.08)	118.7%
Gas	CC	$0.11	(12.5%)
Gas	CT	$0.01	(1.4%)
Gas	Diesel	($0.00)	0.2%
Gas	Steam	($0.03)	3.0%
Interface	Interface	($0.00)	0.0%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.03	(2.8%)
Oil	CT	$0.01	(1.5%)
Oil	Diesel	($0.00)	0.5%
Oil	Steam	$0.02	(2.5%)
Wind	Wind	$0.02	(1.8%)
Total		($0.91)	100.0%

Table 2-25 Average, real-time marginal unit markup index (By price category): January through March 2010 (See 2009 SOM, Table2-35)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.10)	($3.81)
$25 to $50	(0.06)	($2.98)
$50 to $75	0.01	$0.42
$75 to $100	0.02	$0.48
$100 to $125	0.05	$5.44
$125 to $150	0.04	$4.90
> $150	0.11	$21.81

Markup Component of System Price

Table 2-26 Monthly markup components of real-time load-weighted LMP: January through March 2010 (See 2009 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$0.56	$0.00	$1.03
Feb	($1.53)	($1.19)	($1.88)
Mar	($2.01)	($1.38)	($2.73)
2010	($0.91)	($0.85)	($0.97)

Markup Component of Real-Time Zonal Prices

Table 2-27 Average real-time zonal markup component: January through March 2010 (See 2009 SOM, Table 2-37)

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	($0.84)	($0.72)	($0.96)
AEP	($2.31)	($1.84)	($2.76)
AP	($1.35)	($0.97)	($1.72)
BGE	$0.39	$0.37	$0.40
ComEd	($0.56)	($1.07)	($0.02)
DAY	($2.80)	($2.31)	($3.31)
DLCO	($1.63)	$0.41	($3.74)
Dominion	$0.74	$0.24	$1.21
DPL	($0.61)	($0.59)	($0.63)
JCPL	($0.80)	($0.46)	($1.16)
Met-Ed	($0.77)	($0.62)	($0.92)
PECO	($0.83)	($0.72)	($0.93)
PENELEC	($2.16)	($1.83)	($2.50)
Pepco	$0.51	$0.24	$0.79
PPL	($0.85)	($0.69)	($1.01)
PSEG	($1.27)	($1.20)	($1.34)
RECO	($2.00)	($3.01)	($0.86)

Markup by Real-Time System Price Levels

Table 2-28 Average real-time markup component (By price category): January through March 2010 (See 2009 SOM, Table 2-38)

	Average Markup Component	Frequency
Below $20	($5.97)	1.5%
$20 to $40	($3.33)	86.9%
$40 to $60	($1.41)	43.9%
$60 to $80	$3.11	10.9%
$80 to $100	$10.42	4.1%
$100 to $120	$12.81	2.5%
$120 to $140	$25.54	1.8%
$140 to $160	$12.91	0.5%
Above $160	$33.65	0.4%

Day-Ahead Markup

Ownership of Marginal Resources

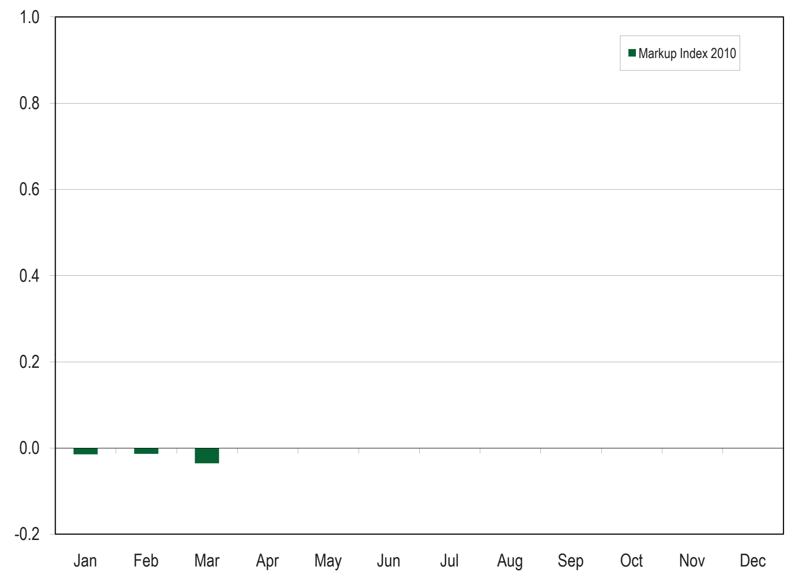
Table 2-29 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through March 2010 (See 2009 SOM, Table 2-39)

Company	Percent of Price
1	23%
2	6%
3	6%
4	6%
5	6%
6	5%
7	5%
8	5%
9	4%
Other (84 companies)	34%

Table 2-30 Day-ahead marginal resources by type/fuel: January through March 2010 (See 2009 SOM, Table 2-40)

Type/Fuel	2010
Transaction	32%
DEC	30%
INC	23%
Coal	10%
Natural gas	4%
Price sensitive demand	1%
Wind	0%
Oil	0%
Municipal waste	0%

Figure 2-6 Day-ahead load-weighted unit markup index: January through March 2010 (See 2009 SOM, Figure 2-6)



Unit Markup Characteristics

Table 2-31 Average, day-ahead marginal unit markup index (By primary fuel and unit type): January through March 2010 (See 2009 SOM, Table 2-41)

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	(0.06)	($2.49)
Municipal waste	Steam	0.02	$0.70
Natural gas	CT	0.09	$8.14
Natural gas	Diesel	(0.18)	($13.59)
Natural gas	Steam	(0.01)	($0.54)
Oil	Steam	(0.11)	($12.42)
Wind	Wind	0.00	$0.00

Table 2-32 Average, day-ahead marginal unit markup index (By price category): January through March 2010 (See 2009 SOM, Table 2-42)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($2.56)
$25 to $50	(0.05)	($2.48)
$50 to $75	0.01	$0.07
$75 to $100	(0.05)	($7.39)
$100 to $125	0.00	($1.19)
$125 to $150	0.04	$4.03
> $150	0.33	$51.27

Markup Component of System Price

Table 2-33 Monthly markup components of day-ahead, load-weighted LMP: January through March 2010 (See 2009 SOM, Table 2-43)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.21)	($0.85)	($1.51)
Feb	($0.86)	($0.61)	($1.11)
Mar	($1.61)	($1.18)	($2.12)
Annual	($1.22)	($0.88)	($1.56)

Markup Component of Zonal Prices

Table 2-34 Day-ahead, average, zonal markup component: January through March 2010 (See 2009 SOM, Table 2-44)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.06)	($0.59)	($1.53)
AEP	($1.79)	($1.20)	($2.36)
AP	($1.23)	($0.87)	($1.58)
BGE	($0.89)	($0.55)	($1.24)
ComEd	($1.07)	($1.03)	($1.11)
DAY	($1.93)	($1.20)	($2.67)
DLCO	($1.74)	($1.08)	($2.43)
Dominion	($0.86)	($0.95)	($0.77)
DPL	($1.03)	($0.57)	($1.47)
JCPL	($1.06)	($0.64)	($1.51)
Met-Ed	($1.04)	($0.63)	($1.46)
PECO	($1.03)	($0.57)	($1.49)
PENELEC	($1.47)	($1.01)	($1.94)
Pepco	($0.91)	($0.66)	($1.15)
PPL	($1.00)	($0.56)	($1.46)
PSEG	($1.05)	($0.57)	($1.58)
RECO	($1.03)	($0.57)	($1.57)

Markup by System Price Levels

Table 2-35 Average, day-ahead markup (By price category): January through March 2010 (See 2009 SOM, Table 2-45)

	Average Markup Component	Frequency
$20 to $40	($2.19)	43%
$40 to $60	($0.38)	43%
$60 to $80	($2.22)	10%
$80 to $100	($0.18)	3%
$100 to $120	$0.53	1%
$120 to $140	$10.49	0%
$140 to $160	$0.00	0%
Above $160	$0.00	0%

Markup Component by Fuel, Unit Type

Table 2-36 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through March 2010 (See 2009 SOM, Table 2-46)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($0.91)	74.5%
Municipal waste	Steam	$0.00	(0.0%)
Natural gas	CT	$0.01	(0.5%)
Natural gas	Diesel	($0.01)	0.5%
Natural gas	Steam	($0.31)	25.0%
Oil	Steam	($0.01)	0.5%
Wind	Wind	$0.00	0.0%
Total		($1.22)	100.0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

Table 2-37 Frequently mitigated units and associated units (By month): January through March 2010 (See 2009 SOM, Table 2-47)

	FMUs and AUs			Total Eligible for
	Tier 1	Tier 2	Tier 3	Any Adder
January	35	31	27	93
February	35	28	31	94
March	42	16	44	102

Table 2-38 Frequently mitigated units and associated units total months eligible: January through March 2010 (See 2009 SOM, Table 2-48)

Months Adder-Eligible	FMU & AU Count
1	8
2	13
3	85
Total	106

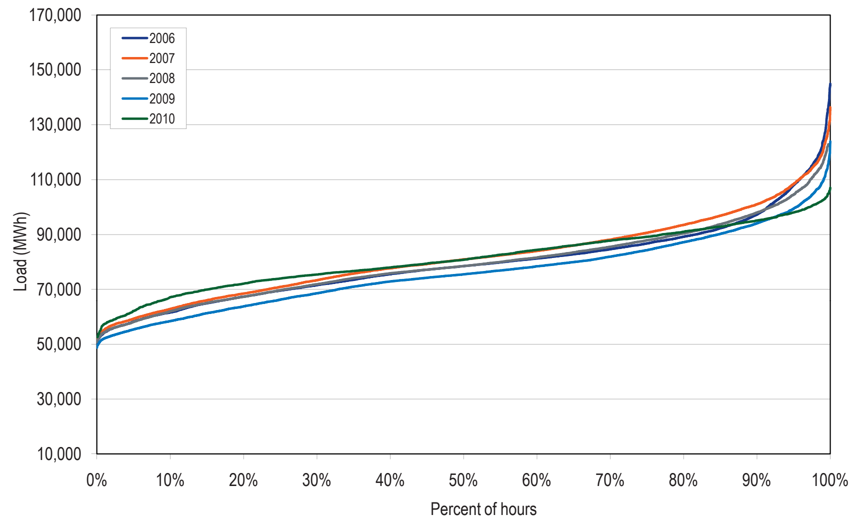
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 PJM real-time load duration curves: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-7)



PJM Real-Time, Annual Average Load

Table 2-39 PJM real-time average load: Calendar years 1998 through March 2010 (See 2009 SOM, Table 2-49)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.5%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)
2009	76,035	75,471	13,260	(4.4%)	(3.8%)	(3.6%)
2010	81,121	80,773	10,694	6.7%	7.0%	(19.4%)

PJM Real-Time, Monthly Average Load

Figure 2-8 PJM real-time average load: Calendar years 2009 through March 2010 (See 2009 SOM, Figure 2-8)

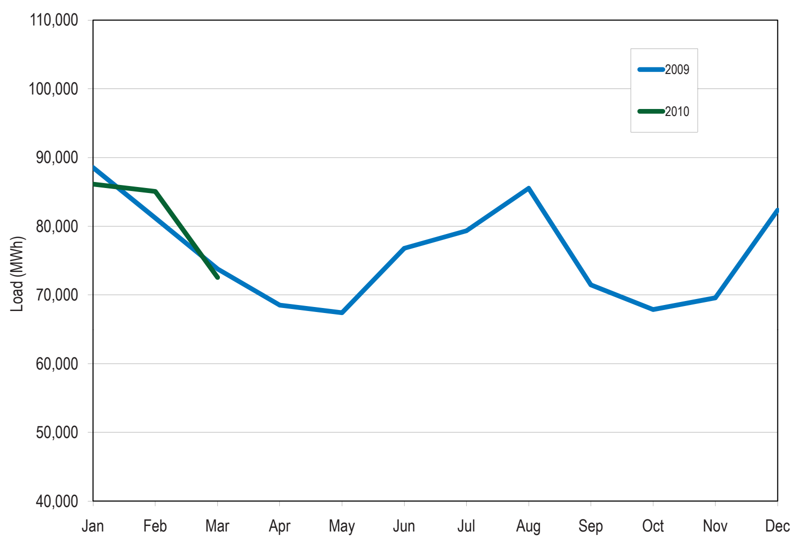


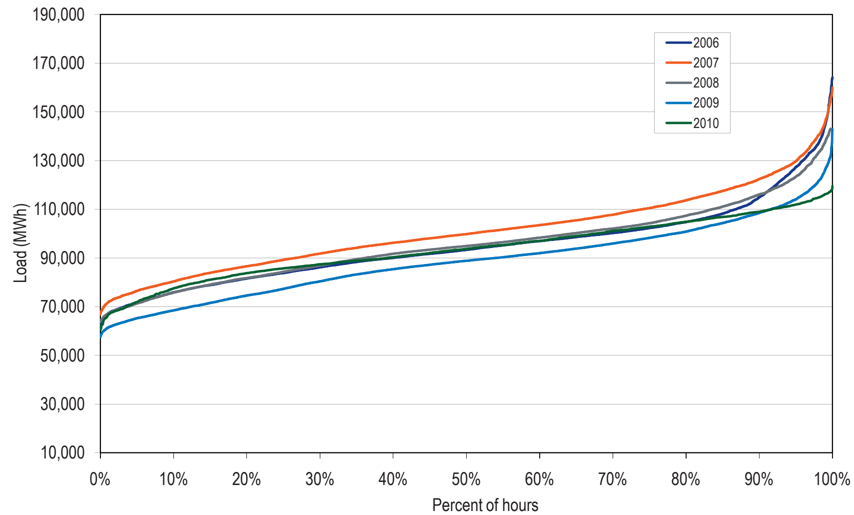
Table 2-40 PJM annual Summer THI, Winter WWP and average temperature: cooling, heating and shoulder months of 2006 through March 2010 (See 2009 SOM, Table 2-51)

	Summer THI	Winter WWP	Shoulder Average Temperature
2006	75.59	31.67	54.62
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09
2010	NA	24.47	46.37

Day-Ahead Load

PJM Day-Ahead Load Duration

Figure 2-9 PJM day-ahead load duration curves: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-9)



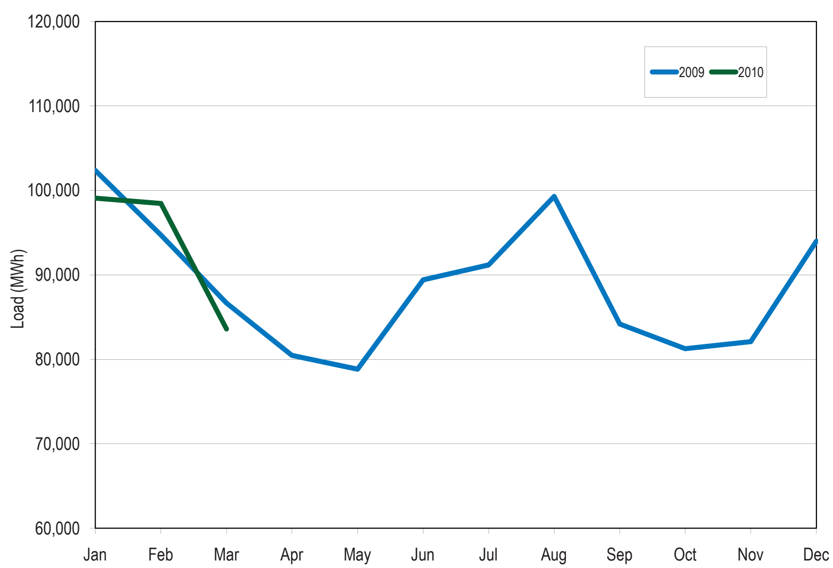
PJM Day-Ahead, Annual Average Load

Table 2-41 PJM day-ahead average load: Calendar years 2000 through March 2010 (See 2009 SOM, Table 2-52)

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	33,045	33,217	6,850	NA	NA	NA
2001	33,318	32,812	6,489	0.8%	(1.2%)	(5.3%)
2002	42,131	40,720	10,130	26.4%	24.1%	56.1%
2003	44,340	44,368	7,883	5.2%	9.0%	(22.2%)
2004	61,034	58,544	16,318	37.7%	32.0%	107.0%
2005	92,002	90,424	17,381	50.7%	54.5%	6.5%
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%
2008	95,522	94,886	15,439	(5.3%)	(4.9%)	(4.6%)
2009	88,707	88,833	14,896	(7.1%)	(6.4%)	(3.5%)
2010	93,559	93,720	11,907	5.5%	5.5%	(20.1%)

PJM Day-Ahead, Monthly Average Load

Figure 2-10 PJM day-ahead average load: Calendar years 2009 through March 2010 (See 2009 SOM, Figure 2-10)

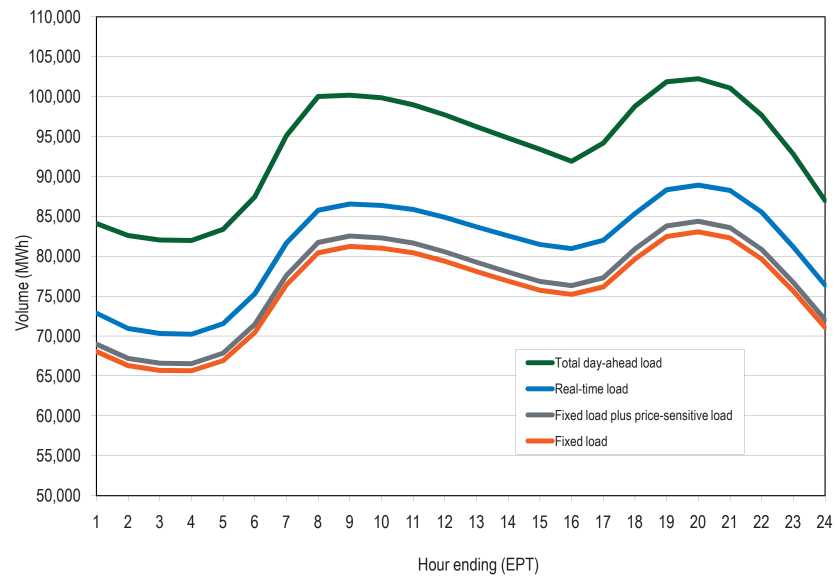


Real-Time and Day-Ahead Load

Table 2-42 Cleared day-ahead and real-time load (MWh): January through March 2010 (See 2009 SOM, Table 2-53)

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bid
Average	75,744	1,132	16,683	93,559	81,121	12,438	(4,245)
Median	75,870	1,091	16,698	93,720	80,773	12,947	(3,751)
Standard deviation	9,860	331	2,187	11,907	10,694	1,213	(974)

Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): January through March 2010 (See 2009 SOM, Figure 2-11)

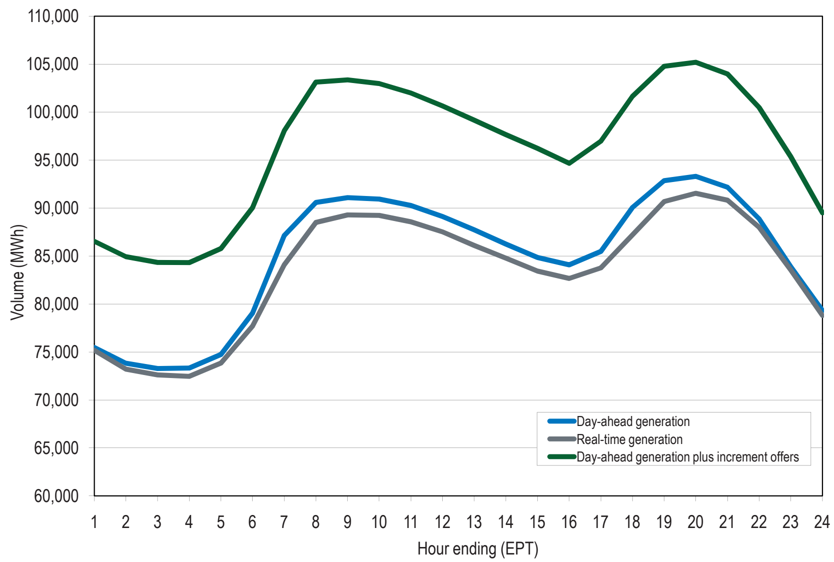


Real-Time and Day-Ahead Generation

Table 2-43 Day-ahead and real-time generation (MWh): January through March 2010 (See 2009 SOM, Table 2-54)

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	84,909	11,416	96,325	83,487	1,422	12,838
Median	85,270	11,357	96,667	83,422	1,848	13,245
Standard deviation	11,374	1,604	12,239	10,998	376	1,242

Figure 2-12 Day-ahead and real-time generation (Average hourly volumes): January through March 2010 (See 2009 SOM, Figure 2-12)



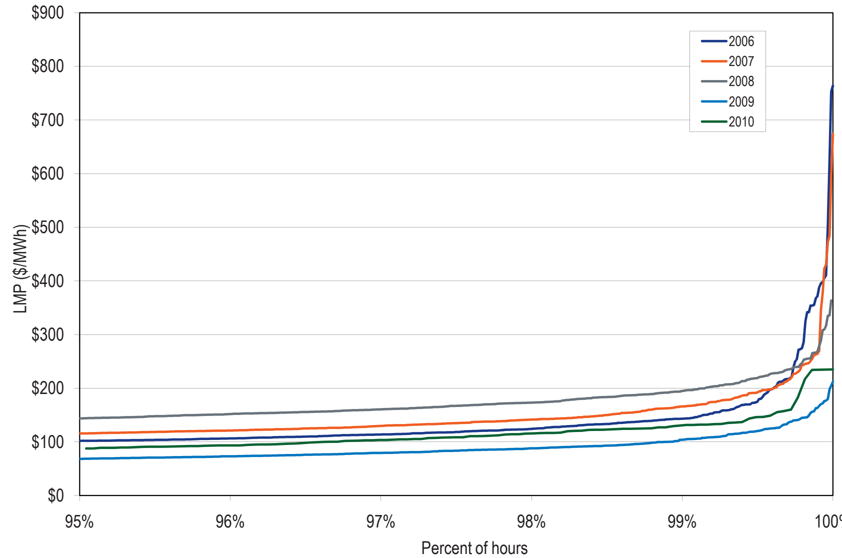
Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

Figure 2-13 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-13)



PJM Real-Time, Annual Average LMP

Table 2-44 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 through March 2010 (See 2009 SOM, Table 2-55)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.13	$37.82	$21.87	19.0%	15.6%	27.7%

Zonal Real-Time, Annual Average LMP

Table 2-45 Zonal real-time, simple average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-56)

	2009 (Jan -Mar)	2010 (Jan -Mar)	Difference	Difference as Percent of 2009
AECO	$54.45	$48.31	($6.14)	(11.3%)
AEP	$41.22	$39.41	($1.81)	(4.4%)
AP	$49.09	$43.67	($5.42)	(11.0%)
BGE	$54.17	$50.44	($3.73)	(6.9%)
ComEd	$34.34	$34.64	$0.30	0.9%
DAY	$40.20	$38.69	($1.50)	(3.7%)
DLCO	$37.12	$39.65	$2.54	6.8%
Dominion	$51.96	$49.43	($2.53)	(4.9%)
DPL	$55.26	$49.01	($6.25)	(11.3%)
JCPL	$54.41	$47.96	($6.45)	(11.9%)
Met-Ed	$53.07	$47.27	($5.80)	(10.9%)
PECO	$53.17	$47.54	($5.63)	(10.6%)
PENELEC	$47.15	$41.83	($5.32)	(11.3%)
Pepco	$53.76	$50.44	($3.33)	(6.2%)
PPL	$52.69	$46.66	($6.03)	(11.4%)
PSEG	$55.20	$49.91	($5.29)	(9.6%)
RECO	$53.65	$46.66	($6.98)	(13.0%)
PJM	$47.29	$44.13	($3.16)	(6.7%)

Real-Time, Annual Average LMP by Jurisdiction

Table 2-46 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-57)

	2009 (Jan -Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
Delaware	$54.79	$48.30	($6.48)	(11.8%)
Illinois	$34.34	$34.64	$0.30	0.9%
Indiana	$39.87	$37.85	($2.02)	(5.1%)
Kentucky	$41.31	$40.21	($1.10)	(2.7%)
Maryland	$54.24	$50.18	($4.05)	(7.5%)
Michigan	$41.09	$38.54	($2.54)	(6.2%)
New Jersey	$54.85	$49.08	($5.77)	(10.5%)
North Carolina	$50.10	$48.01	($2.09)	(4.2%)
Ohio	$39.89	$38.04	($1.85)	(4.6%)
Pennsylvania	$50.11	$45.06	($5.04)	(10.1%)
Tennessee	$41.73	$41.90	$0.17	0.4%
Virginia	$50.90	$48.59	($2.31)	(4.5%)
West Virginia	$43.66	$39.81	($3.86)	(8.8%)
District of Columbia	$53.82	$50.72	($3.10)	(5.8%)

Hub Real-Time, Annual Average LMP

Table 2-47 Hub real-time, simple average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-58)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
AEP Gen Hub	$38.21	$36.33	($1.88)	(4.9%)
AEP-DAY Hub	$40.29	$38.26	($2.03)	(5.0%)
Chicago Gen Hub	$33.34	$33.98	$0.64	1.9%
Chicago Hub	$34.57	$34.78	$0.21	0.6%
Dominion Hub	$50.94	$48.75	($2.19)	(4.3%)
Eastern Hub	$54.89	$48.93	($5.96)	(10.9%)
N Illinois Hub	$34.09	$34.47	$0.38	1.1%
New Jersey Hub	$54.80	$48.90	($5.90)	(10.8%)
Ohio Hub	$40.09	$38.22	($1.88)	(4.7%)
West Interface Hub	$42.39	$40.96	($1.43)	(3.4%)
Western Hub	$49.19	$44.54	($4.65)	(9.4%)

Real-Time, Load-Weighted, Average LMP

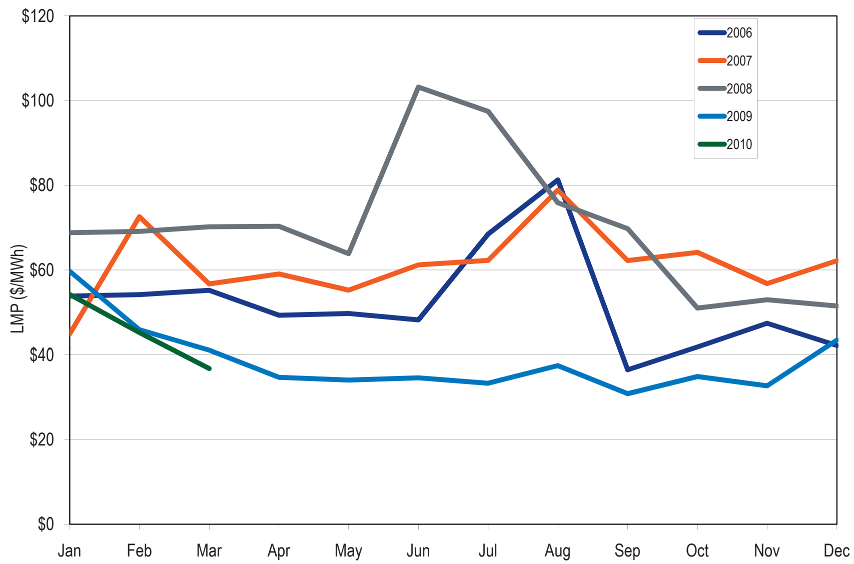
PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-48 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through March 2010 (See 2009 SOM, Table 2-59)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$45.92	$39.01	$22.99	17.6%	14.0%	26.3%

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 2-14 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-14)



Zonal Real-Time, Annual, Load-Weighted, Average LMP

Table 2-49 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-60)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
AECO	$56.96	$50.19	($6.77)	(11.9%)
AEP	$43.00	$40.81	($2.19)	(5.1%)
AP	$51.70	$45.27	($6.43)	(12.4%)
BGE	$57.47	$53.28	($4.19)	(7.3%)
ComEd	$35.88	$35.85	($0.03)	(0.1%)
DAY	$41.96	$40.06	($1.91)	(4.5%)
DLCO	$37.93	$40.83	$2.89	7.6%
Dominion	$55.71	$52.88	($2.84)	(5.1%)
DPL	$59.09	$51.74	($7.36)	(12.4%)
JCPL	$57.12	$49.95	($7.17)	(12.5%)
Met-Ed	$55.94	$49.14	($6.80)	(12.2%)
PECO	$55.69	$49.39	($6.30)	(11.3%)
PENELEC	$48.92	$42.93	($6.00)	(12.3%)
Pepco	$57.00	$53.24	($3.75)	(6.6%)
PPL	$55.70	$48.69	($7.01)	(12.6%)
PSEG	$57.34	$51.60	($5.74)	(10.0%)
RECO	$55.96	$48.33	($7.63)	(13.6%)
PJM	$49.60	$45.92	($3.68)	(7.4%)

Real-Time, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-50 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-61)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
Delaware	$58.16	$50.55	($7.61)	(13.1%)
Illinois	$35.88	$35.85	($0.03)	(0.1%)
Indiana	$40.97	$38.66	($2.32)	(5.7%)
Kentucky	$43.91	$42.29	($1.62)	(3.7%)
Maryland	$57.89	$53.22	($4.68)	(8.1%)
Michigan	$42.34	$39.63	($2.71)	(6.4%)
New Jersey	$57.20	$50.87	($6.33)	(11.1%)
North Carolina	$54.06	$51.81	($2.25)	(4.2%)
Ohio	$41.34	$39.15	($2.18)	(5.3%)
Pennsylvania	$52.44	$46.66	($5.78)	(11.0%)
Tennessee	$44.63	$45.24	$0.61	1.4%
Virginia	$54.64	$51.95	($2.69)	(4.9%)
West Virginia	$45.99	$41.36	($4.64)	(10.1%)
District of Columbia	$56.10	$52.70	($3.40)	(6.1%)

Real-Time, Fuel-Cost-Adjusted, Load-Weighted LMP

Fuel Cost

Figure 2-15 Spot average fuel price comparison: Calendar years 2009 through March 2010 (See 2009 SOM, Figure 2-15)

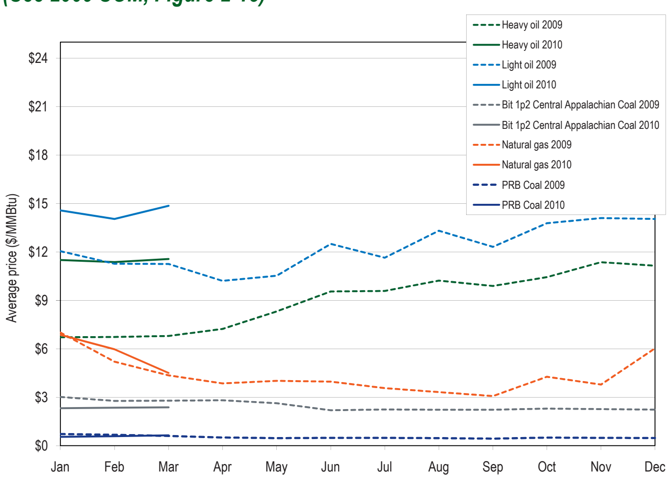


Figure 2-16 Spot average emission price comparison: Calendar years 2009 through March 2010 (See 2009 SOM, Figure 2-16)

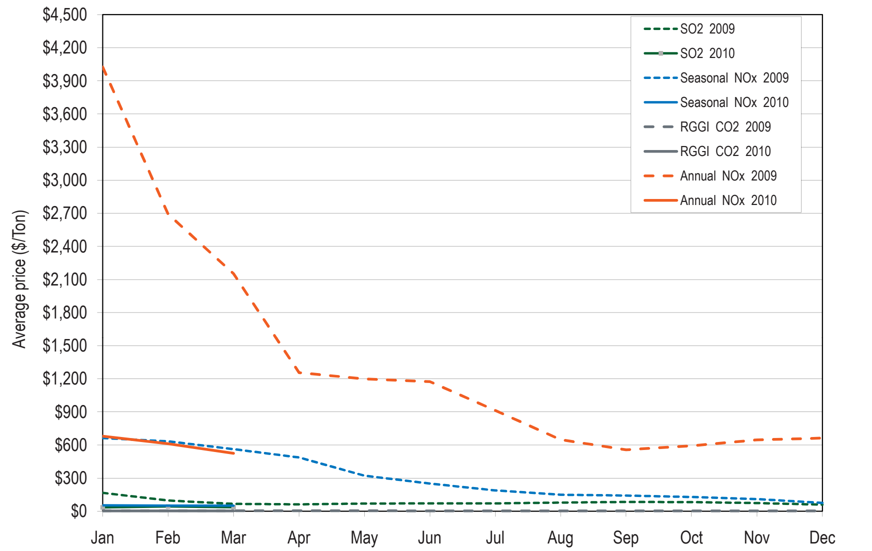


Table 2-51 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2009 SOM, Table 2-62)

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408

Table 2-52 PJM real-time annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January 1, 2010, through March 31, 2010 (See 2009 SOM, Table 2-63)

	2009 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$49.60	$53.56	8.0%

Components of Real-Time, Load-Weighted LMP

Table 2-53 Components of PJM real-time, annual, load-weighted, average LMP: January 1, 2010, through March 31, 2010 (See 2009 SOM, Table 2-64)

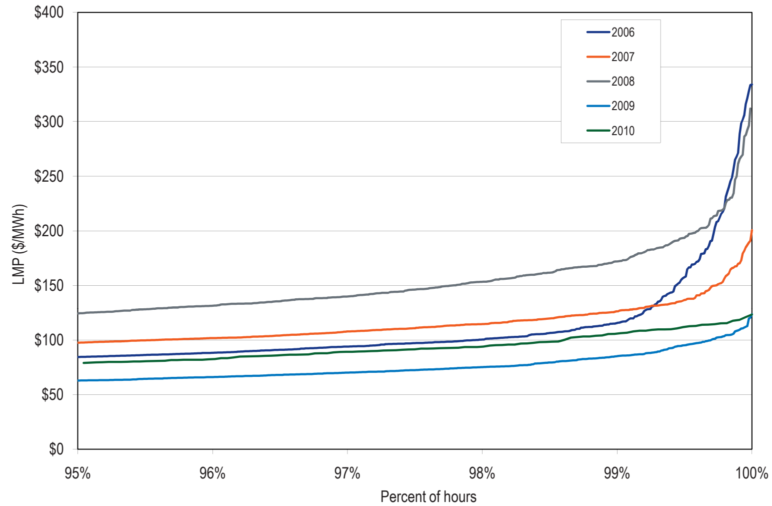
Element	Contribution to LMP	Percent
Coal	$21.06	45.9%
Gas	$16.91	36.8%
10% Cost Adder	$4.24	9.2%
VOM	$2.32	5.1%
NOX	$1.17	2.5%
CO2	$0.45	1.0%
Oil	$0.38	0.8%
SO2	$0.28	0.6%
Dispatch Differential	$0.07	0.2%
NA	$0.06	0.1%
FMU Adder	$0.04	0.1%
Shadow Price Limit Adder	$0.03	0.1%
M2M Adder	$0.01	0.0%
Offline CT Adder	$0.01	0.0%
Municipal Waste	$0.00	0.0%
UDS Override Differential	($0.20)	(0.4%)
Markup	($0.91)	(2.0%)
LMP	$45.92	100.0%

Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

Figure 2-17 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-17)



PJM Day-Ahead, Annual Average LMP

Table 2-54 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 through March 2010 (See 2009 SOM, Table 2-65)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$46.13	$41.99	$15.93	24.7%	19.4%	19.0%

Zonal Day-Ahead, Annual Average LMP

Table 2-55 Zonal day-ahead, simple average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-66)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
AECO	$55.65	$50.98	($4.66)	(8.4%)
AEP	$40.92	$40.38	($0.54)	(1.3%)
AP	$48.30	$45.11	($3.19)	(6.6%)
BGE	$55.94	$53.96	($1.98)	(3.5%)
ComEd	$35.01	$35.75	$0.74	2.1%
DAY	$39.43	$39.22	($0.21)	(0.5%)
DLCO	$36.44	$39.71	$3.27	9.0%
Dominion	$53.16	$53.30	$0.14	0.3%
DPL	$56.29	$51.32	($4.97)	(8.8%)
JCPL	$55.70	$51.09	($4.61)	(8.3%)
Met-Ed	$54.25	$50.23	($4.02)	(7.4%)
PECO	$54.81	$50.53	($4.29)	(7.8%)
PENELEC	$47.55	$44.51	($3.04)	(6.4%)
Pepco	$55.46	$54.23	($1.23)	(2.2%)
PPL	$53.77	$49.71	($4.06)	(7.5%)
PSEG	$56.49	$52.23	($4.26)	(7.5%)
RECO	$54.80	$50.69	($4.11)	(7.5%)
PJM	$47.41	$46.13	($1.28)	(2.7%)

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-56 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-67)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
Delaware	$55.52	$50.73	($4.79)	(8.6%)
Illinois	$35.01	$35.75	$0.74	2.1%
Indiana	$39.30	$38.60	($0.71)	(1.8%)
Kentucky	$40.93	$40.81	($0.13)	(0.3%)
Maryland	$55.83	$53.50	($2.32)	(4.2%)
Michigan	$40.28	$39.18	($1.10)	(2.7%)
New Jersey	$56.12	$51.73	($4.40)	(7.8%)
North Carolina	$51.10	$51.71	$0.60	1.2%
Ohio	$39.32	$38.58	($0.74)	(1.9%)
Pennsylvania	$50.85	$47.48	($3.38)	(6.6%)
Tennessee	$41.94	$43.18	$1.24	3.0%
Virginia	$52.03	$52.22	$0.20	0.4%
West Virginia	$43.10	$40.63	($2.48)	(5.7%)
District of Columbia	$55.54	$54.58	($0.96)	(1.7%)

Day-Ahead, Load-Weighted, Average LMP

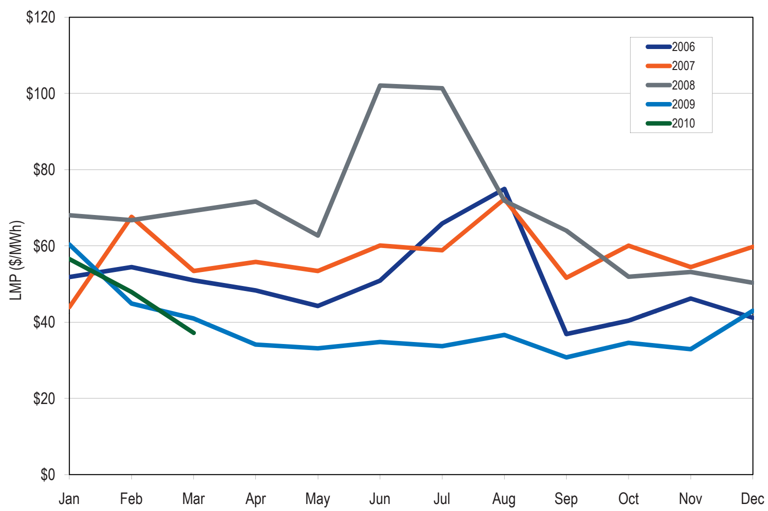
PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-57 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through March 2010 (See 2009 SOM, Table 2-68)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.77	$43.62	$16.52	23.1%	19.0%	17.8%

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 2-18 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2006 through March 2010 (See 2009 SOM, Figure 2-18)



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-58 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through March 2009 to 2010 (See 2009 SOM, Table 2-69)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
AECO	$58.96	$53.66	($5.30)	(9.0%)
AEP	$42.44	$41.63	($0.80)	(1.9%)
AP	$50.54	$46.61	($3.93)	(7.8%)
BGE	$58.82	$56.54	($2.28)	(3.9%)
ComEd	$36.04	$36.57	$0.53	1.5%
DAY	$40.93	$40.48	($0.45)	(1.1%)
DLCO	$37.34	$41.01	$3.67	9.8%
Dominion	$56.48	$56.74	$0.26	0.5%
DPL	$59.40	$53.72	($5.68)	(9.6%)
JCPL	$58.00	$52.89	($5.11)	(8.8%)
Met-Ed	$57.37	$52.07	($5.30)	(9.2%)
PECO	$57.28	$52.47	($4.81)	(8.4%)
PENELEC	$49.56	$45.47	($4.09)	(8.3%)
Pepco	$58.12	$56.02	($2.10)	(3.6%)
PPL	$56.40	$51.86	($4.54)	(8.1%)
PSEG	$58.73	$53.75	($4.98)	(8.5%)
RECO	$57.40	$53.11	($4.29)	(7.5%)
PJM	$49.44	$47.77	($1.67)	(3.4%)

Day-Ahead, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-59 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-70)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Difference	Difference as Percent of 2009
Delaware	$58.69	$53.05	($5.64)	(9.6%)
Illinois	$36.04	$36.57	$0.53	1.5%
Indiana	$40.64	$39.57	($1.06)	(2.6%)
Kentucky	$42.67	$42.19	($0.48)	(1.1%)
Maryland	$58.96	$55.89	($3.06)	(5.2%)
Michigan	$41.47	$39.96	($1.51)	(3.6%)
New Jersey	$58.49	$53.46	($5.03)	(8.6%)
North Carolina	$54.41	$54.78	$0.37	0.7%
Ohio	$40.74	$39.65	($1.09)	(2.7%)
Pennsylvania	$53.17	$49.00	($4.17)	(7.8%)
Tennessee	$43.74	$45.10	$1.36	3.1%
Virginia	$55.06	$55.36	$0.29	0.5%
West Virginia	$44.76	$41.98	($2.77)	(6.2%)
District of Columbia	$57.75	$55.86	($1.89)	(3.3%)

Components of Day-Ahead, Load-Weighted LMP

Table 2-60 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-71)

Element	Contribution to LMP	Percent
INC	$17.56	36.8%
DEC	$12.78	26.7%
Coal	$7.45	15.6%
Natural gas	$4.55	9.5%
Transaction	$2.22	4.6%
Price sensitive demand	$1.77	3.7%
%10 Cost offer	$1.34	2.8%
VOM	$0.69	1.4%
NOx	$0.40	0.8%
SO2	$0.14	0.3%
CO2	$0.10	0.2%
Oil	$0.05	0.1%
Constrained off	$0.00	0.0%
Markup	($1.22)	(2.5%)
NA	($0.06)	(0.1%)
Total	$47.77	100.0%

Marginal Losses

Table 2-61 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through March 2010 (See 2009 SOM, Table 2-72)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$44.13	$44.02	$0.06	$0.05

Table 2-62 Zonal real-time, simple average LMP components (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-73)

	2009 (Jan - Mar)				2010 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$54.45	$47.21	$4.68	$2.56	$48.31	$44.02	$1.73	$2.55
AEP	$41.22	$47.21	($4.29)	($1.70)	$39.41	$44.02	($2.98)	($1.64)
AP	$49.09	$47.21	$1.97	($0.09)	$43.67	$44.02	($0.33)	($0.02)
BGE	$54.17	$47.21	$4.85	$2.12	$50.44	$44.02	$4.06	$2.36
ComEd	$34.34	$47.21	($9.76)	($3.11)	$34.64	$44.02	($6.15)	($3.23)
DAY	$40.20	$47.21	($5.72)	($1.30)	$38.69	$44.02	($4.15)	($1.18)
DLCO	$37.12	$47.21	($8.13)	($1.96)	$39.65	$44.02	($2.67)	($1.70)
Dominion	$51.96	$47.21	$4.19	$0.57	$49.43	$44.02	$4.52	$0.89
DPL	$55.26	$47.21	$5.19	$2.86	$49.01	$44.02	$2.18	$2.81
JCPL	$54.41	$47.21	$4.27	$2.93	$47.96	$44.02	$1.34	$2.59
Met-Ed	$53.07	$47.21	$4.36	$1.50	$47.27	$44.02	$1.71	$1.54
PECO	$53.17	$47.21	$3.99	$1.97	$47.54	$44.02	$1.72	$1.80
PENELEC	$47.15	$47.21	($0.04)	($0.01)	$41.83	$44.02	($1.93)	($0.26)
Pepco	$53.76	$47.21	$5.20	$1.36	$50.44	$44.02	$4.86	$1.56
PPL	$52.69	$47.21	$4.16	$1.32	$46.66	$44.02	$1.47	$1.16
PSEG	$55.20	$47.21	$5.04	$2.96	$49.91	$44.02	$3.31	$2.58
RECO	$53.65	$47.21	$3.81	$2.63	$46.66	$44.02	$0.44	$2.20

Table 2-63 Hub real-time, simple average LMP components (Dollars per MWh): January through March 2010 (See 2009 SOM, 2-74)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$36.33	$44.02	($4.48)	($3.21)
AEP-DAY Hub	$38.26	$44.02	($3.86)	($1.91)
Chicago Gen Hub	$33.98	$44.02	($6.26)	($3.78)
Chicago Hub	$34.78	$44.02	($6.03)	($3.21)
Dominion Hub	$48.75	$44.02	$4.36	$0.37
Eastern Hub	$48.93	$44.02	$1.98	$2.93
N Illinois Hub	$34.47	$44.02	($6.12)	($3.44)
New Jersey Hub	$48.90	$44.02	$2.35	$2.53
Ohio Hub	$38.22	$44.02	($3.91)	($1.90)
West Interface Hub	$40.96	$44.02	($1.59)	($1.48)
Western Hub	$44.54	$44.02	$0.68	($0.16)

Zonal and PJM Real-Time, Annual, Load-Weighted, Average LMP Components

Table 2-64 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-75)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$50.19	$45.66	$1.89	$2.64
AEP	$40.81	$45.75	($3.26)	($1.68)
AP	$45.27	$45.85	($0.54)	($0.03)
BGE	$53.28	$46.16	$4.62	$2.50
ComEd	$35.85	$45.26	($6.11)	($3.30)
DAY	$40.06	$45.73	($4.50)	($1.18)
DLCO	$40.83	$45.33	($2.73)	($1.77)
Dominion	$52.88	$46.50	$5.39	$0.98
DPL	$51.74	$46.31	$2.44	$2.98
JCPL	$49.95	$45.78	$1.47	$2.70
Met-Ed	$49.14	$45.71	$1.83	$1.59
PECO	$49.39	$45.69	$1.85	$1.85
PENELEC	$42.93	$45.39	($2.16)	($0.30)
Pepco	$53.24	$46.16	$5.44	$1.64
PPL	$48.69	$45.89	$1.60	$1.20
PSEG	$51.60	$45.38	$3.56	$2.65
RECO	$48.33	$45.48	$0.57	$2.28
PJM	$45.92	$45.81	$0.06	$0.05

Table 2-65 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 through March 2010 (See 2009 SOM, Table 2-76)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	($0.06)	($0.09)
2010	$46.13	$46.10	$0.01	$0.02

Table 2-66 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through March 2009 and 2010 (See 2009 SOM, Table 2-77)

	2009 (Jan - Mar)				2010 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$55.65	$47.72	$4.63	$3.29	$50.98	$46.10	$2.11	$2.77
AEP	$40.92	$47.72	($4.64)	($2.17)	$40.38	$46.10	($3.49)	($2.23)
AP	$48.30	$47.72	$0.42	$0.15	$45.11	$46.10	($1.04)	$0.05
BGE	$55.94	$47.72	$5.79	$2.43	$53.96	$46.10	$4.64	$3.22
ComEd	$35.01	$47.72	($8.40)	($4.32)	$35.75	$46.10	($6.12)	($4.23)
DAY	$39.43	$47.72	($6.27)	($2.02)	$39.22	$46.10	($4.79)	($2.09)
DLCO	$36.44	$47.72	($8.88)	($2.41)	$39.71	$46.10	($4.39)	($2.00)
Dominion	$53.16	$47.72	$4.46	$0.97	$53.30	$46.10	$5.61	$1.58
DPL	$56.29	$47.72	$5.10	$3.46	$51.32	$46.10	$2.36	$2.85
JCPL	$55.70	$47.72	$4.18	$3.80	$51.09	$46.10	$1.77	$3.21
Met-Ed	$54.25	$47.72	$4.61	$1.91	$50.23	$46.10	$2.32	$1.81
PECO	$54.81	$47.72	$4.34	$2.75	$50.53	$46.10	$2.14	$2.28
PENELEC	$47.55	$47.72	($0.37)	$0.19	$44.51	$46.10	($1.97)	$0.37
Pepco	$55.46	$47.72	$5.79	$1.95	$54.23	$46.10	$5.69	$2.44
PPL	$53.77	$47.72	$4.30	$1.74	$49.71	$46.10	$2.23	$1.38
PSEG	$56.49	$47.72	$4.78	$3.99	$52.23	$46.10	$2.76	$3.37
RECO	$54.80	$47.72	$3.44	$3.64	$50.69	$46.10	$1.69	$2.90

Zonal and PJM Day-Ahead, Annual, Load-Weighted, Average LMP Components

Table 2-67 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-78)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$53.66	$48.41	$2.28	$2.96
AEP	$41.63	$47.76	($3.82)	($2.31)
AP	$46.61	$47.84	($1.27)	$0.04
BGE	$56.54	$48.05	$5.09	$3.39
ComEd	$36.57	$47.12	($6.23)	($4.32)
DAY	$40.48	$47.83	($5.20)	($2.15)
DLCO	$41.01	$47.40	($4.33)	($2.06)
Dominion	$56.74	$48.42	$6.62	$1.70
DPL	$53.72	$48.19	$2.54	$2.99
JCPL	$52.89	$47.70	$1.85	$3.35
Met-Ed	$52.07	$47.74	$2.45	$1.88
PECO	$52.47	$47.84	$2.26	$2.36
PENELEC	$45.47	$47.20	($2.09)	$0.36
Pepco	$56.02	$47.47	$6.03	$2.52
PPL	$51.86	$48.00	$2.39	$1.47
PSEG	$53.75	$47.40	$2.89	$3.47
RECO	$53.11	$48.22	$1.82	$3.06
PJM	$47.77	$47.74	$0.01	$0.02

Marginal Loss Accounting

Monthly Marginal Loss Costs

Table 2-68 Marginal loss costs by type (Dollars (Millions)): January through March 2010 (See 2009 SOM, Table 2-79)

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$45.5	($136.3)	$7.0	$188.9	$1.2	($2.8)	($4.0)	$0.0	$188.9
Feb	$31.6	($100.1)	$3.0	$134.7	$0.4	($0.6)	($1.3)	($0.4)	$134.3
Mar	$21.0	($70.5)	$2.7	$94.2	$0.2	($0.2)	($1.2)	($0.8)	$93.4
Total	$98.0	($307.0)	$12.8	$417.8	$1.8	($3.5)	($6.5)	($1.2)	$416.6

Zonal Marginal Loss Costs

Table 2-69 Marginal loss costs by control zone and type (Dollars (Millions)): January through March 2010 (See 2009 SOM, Table 2-80)

Marginal Loss Costs by Control Zone (Millions)									
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$6.8	$2.1	$0.0	$4.7	$0.7	($0.2)	($0.0)	$0.8	$5.6
AEP	($17.3)	($96.5)	$5.6	$84.7	($1.1)	$1.3	($0.0)	($2.4)	$82.3
AP	$0.7	($30.6)	$3.2	$34.5	$0.8	$1.3	($2.1)	($2.7)	$31.8
BGE	$23.9	$7.6	$1.4	$17.6	$1.7	($0.9)	($1.1)	$1.5	$19.2
ComEd	($56.4)	($136.2)	$0.1	$79.9	($0.7)	($0.7)	($0.1)	($0.2)	$79.8
DAY	($1.6)	($17.8)	$1.4	$17.6	$0.0	$0.5	($0.9)	($1.3)	$16.2
DLCO	($13.0)	($20.3)	$0.1	$7.4	($0.6)	($0.2)	($0.0)	($0.4)	$6.9
Dominion	$34.6	($8.5)	$1.6	$44.7	$0.8	($0.2)	($0.7)	$0.3	$45.0
DPL	$14.3	$2.6	$0.1	$11.9	($0.4)	($0.4)	($0.0)	$0.0	$11.9
JCPL	$18.2	$5.1	$0.1	$13.2	$0.1	($0.4)	($0.1)	$0.5	$13.7
Met-Ed	$7.7	$2.1	$0.0	$5.6	$0.0	($0.2)	($0.0)	$0.2	$5.8
PECO	$15.9	$6.4	$0.0	$9.5	($0.1)	($0.7)	($0.0)	$0.6	$10.2
PENELEC	($2.7)	($21.6)	($0.0)	$18.9	$0.7	($1.5)	$0.1	$2.3	$21.2
Pepco	$35.6	$18.0	$1.0	$18.6	($0.7)	$0.3	($0.7)	($1.7)	$16.8
PJM	($14.8)	($25.8)	($6.5)	$4.5	$0.8	($3.9)	$3.0	$7.6	$12.1
PPL	$15.4	($2.6)	$0.5	$18.5	$0.6	$0.2	($0.1)	$0.3	$18.8
PSEG	$29.7	$8.7	$4.2	$25.2	($1.0)	$2.5	($3.6)	($7.0)	$18.2
RECO	$1.0	$0.2	$0.0	$0.7	$0.1	($0.2)	($0.0)	$0.3	$1.0
Total	$98.0	($307.0)	$12.8	$417.8	$1.8	($3.5)	($6.5)	($1.2)	$416.6

Table 2-70 Monthly marginal loss costs by control zone (Dollars (Millions)): January through March 2010 (See 2009 SOM, Table 2-81)

	Marginal Loss Costs by Control Zone (Millions)			
	Jan	Feb	Mar	Grand Total
AECO	$2.6	$1.5	$1.4	$5.6
AEP	$40.0	$25.9	$16.4	$82.3
AP	$13.7	$11.2	$6.8	$31.8
BGE	$8.8	$6.7	$3.7	$19.2
ComEd	$36.1	$23.9	$19.8	$79.8
DAY	$6.6	$5.3	$4.2	$16.2
DLCO	$3.0	$2.3	$1.6	$6.9
Dominion	$20.1	$15.9	$9.0	$45.0
DPL	$5.7	$3.6	$2.6	$11.9
JCPL	$6.3	$4.0	$3.3	$13.7
Met-Ed	$2.8	$1.6	$1.4	$5.8
PECO	$4.2	$3.7	$2.3	$10.2
PENELEC	$10.4	$7.2	$3.6	$21.2
Pepco	$6.7	$5.7	$4.5	$16.8
PJM	$5.5	$3.7	$2.9	$12.1
PPL	$8.8	$6.3	$3.7	$18.8
PSEG	$7.0	$5.4	$5.8	$18.2
RECO	$0.5	$0.2	$0.2	$1.0
Total	$188.9	$134.3	$93.4	$416.6

Virtual Offers and Bids

Table 2-71 Monthly volume of cleared and submitted INCs, DECs: January through March 2010 (See 2009 SOM, Table 2-82)

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	11,144	21,634	282	936	266	893	17,513	29,406
Feb	12,387	23,827	387	1,122	270	883	17,602	28,542
Mar	10,811	21,062	308	915	253	763	15,019	24,968
Apr								
May								
Jun								
Jul								
Aug								
Sep								
Oct								
Nov								
Dec								
Annual	11,416	22,120	324	987	263	845	16,683	27,610

Table 2-72 Type of day-ahead marginal units: January through March 2010 (See 2009 SOM, Table 2-83)

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	16.5%	30.9%	32.5%	19.4%	0.7%
Feb	14.9%	34.1%	24.3%	26.1%	0.6%
Mar	10.6%	29.9%	34.1%	24.7%	0.7%
Annual	14.0%	31.5%	30.5%	23.3%	0.7%

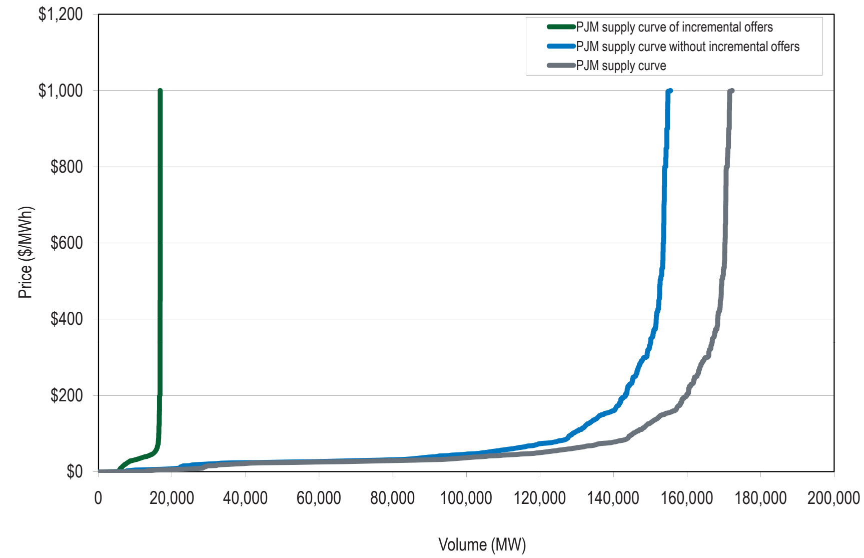
Table 2-73 PJM virtual bids by type of bid parent organization (MW): January through March 2010 (See 2009 SOM, Table 2-84)

	Category	Total Virtual Bids MW	Percentage
2010	Financial	31,153,605	29.0%
2010	Physical	76,211,805	71.0%
2010	Total	107,365,411	100%

Table 2-74 PJM virtual bids by top ten locations (MW): January through March 2010 (See 2009 SOM, Table 2-85)

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	15,893,424	20,073,663	35,967,087
N ILLINOIS HUB	HUB	2,240,556	2,230,829	4,471,386
AEP-DAYTON HUB	HUB	1,479,029	1,861,400	3,340,428
PSEG	ZONE	687,928	1,666,222	2,354,149
PPL	ZONE	142,046	2,122,986	2,265,032
PEPCO	ZONE	1,793,453	409,615	2,203,068
BGE	ZONE	1,060,024	1,060,062	2,120,086
JCPL	ZONE	1,133,979	818,916	1,952,895
IMO	INTERFACE	1,057,722	439,498	1,497,220
MISO	INTERFACE	401,712	621,594	1,023,306

Figure 2-19 PJM day-ahead aggregate supply curves: 2010 example day (See 2009 SOM, Figure 2-19)



Price Convergence

Table 2-75 Day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-86)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$46.13	$44.13	($2.00)	(4.5%)
Median	$41.99	$37.82	($4.17)	(11.0%)
Standard deviation	$15.93	$21.87	$5.93	27.1%

Table 2-76 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 through March 2010 (See 2009 SOM, Table 2-87)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
2000	$31.97	$30.36	($1.61)	(5.3%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.0%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$46.13	$44.13	($2.00)	(4.5%)

Table 2-77 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2006 through March 2010 (See 2009 SOM, Table 2-88)

	2006		2007		2008		2009		2010	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	1	0.01%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	1	0.02%	0	0.00%	1	0.01%	0	0.00%	0	0.00%
($100) to ($50)	9	0.13%	33	0.38%	88	1.01%	3	0.03%	5	0.23%
($50) to $0	5,205	59.54%	4,600	52.89%	5,120	59.30%	5,108	58.34%	1,569	72.90%
$0 to $50	3,372	98.04%	3,827	96.58%	3,247	96.27%	3,603	99.47%	547	98.24%
$50 to $100	152	99.77%	255	99.49%	284	99.50%	41	99.94%	33	99.77%
$100 to $150	9	99.87%	31	99.84%	37	99.92%	5	100.00%	1	99.81%
$150 to $200	4	99.92%	5	99.90%	4	99.97%	0	100.00%	4	100.00%
$200 to $250	1	99.93%	1	99.91%	2	99.99%	0	100.00%	0	100.00%
$250 to $300	3	99.97%	3	99.94%	0	99.99%	0	100.00%	0	100.00%
$300 to $350	0	99.97%	2	99.97%	1	100.00%	0	100.00%	0	100.00%
$350 to $400	1	99.98%	1	99.98%	0	100.00%	0	100.00%	0	100.00%
$400 to $450	0	99.98%	1	99.99%	0	100.00%	0	100.00%	0	100.00%
$450 to $500	1	99.99%	1	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-20 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through March 2010 (See 2009 SOM, Figure 2-20)

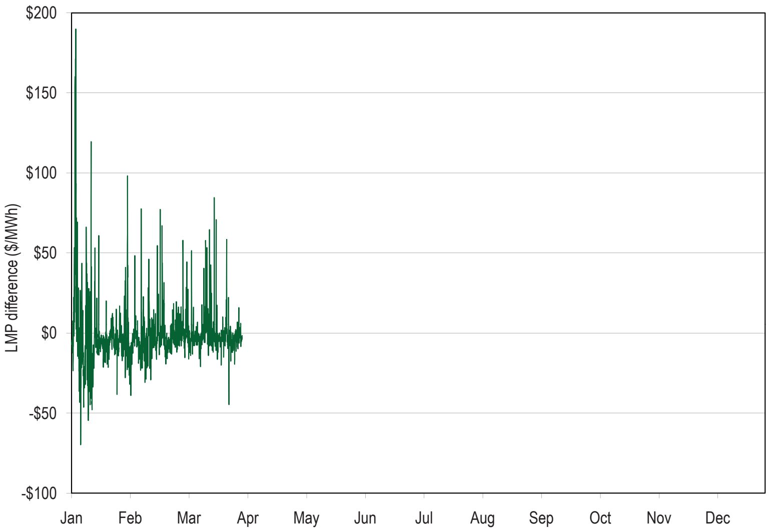


Figure 2-21 Monthly simple average of real-time minus day-ahead LMP: January through March 2010 (See 2009 SOM, Figure 2-21)

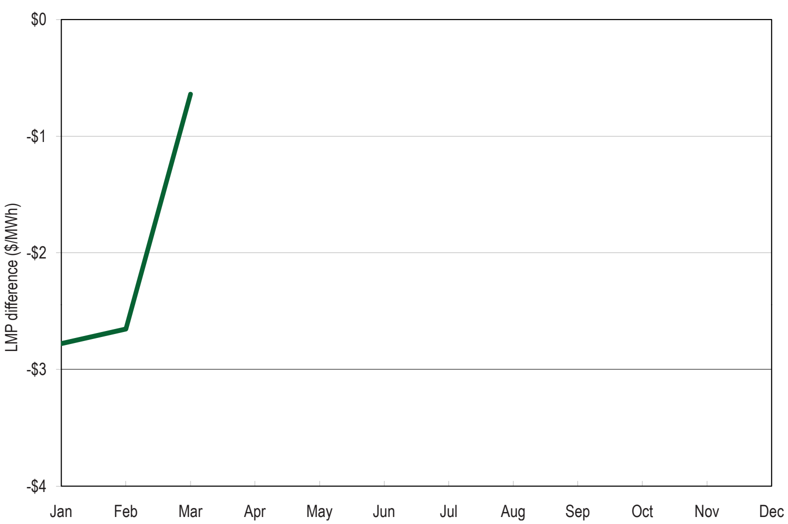
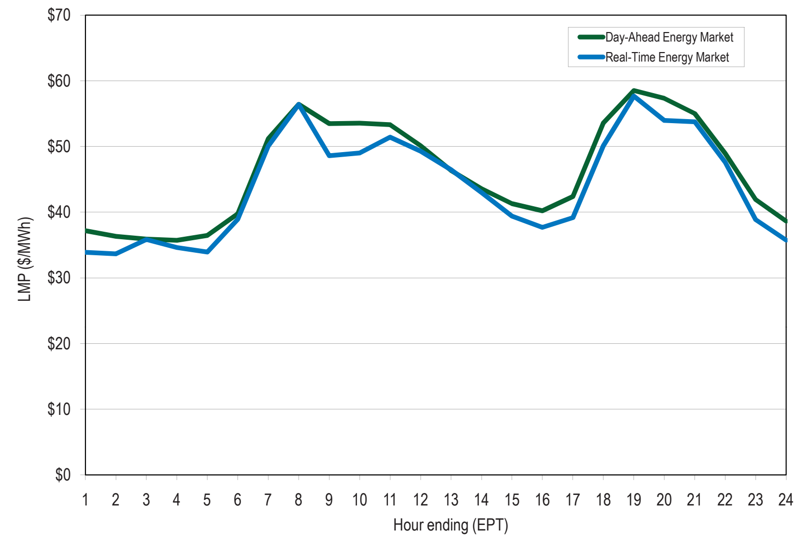


Figure 2-22 PJM system simple hourly average LMP: January through March 2010 (See 2009 SOM, Figure 2-22)



Zonal Price Convergence

Table 2-78 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-89)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$50.98	$48.31	($2.68)	(5.5%)
AEP	$40.38	$39.41	($0.97)	(2.5%)
AP	$45.11	$43.67	($1.44)	(3.3%)
BGE	$53.96	$50.44	($3.52)	(7.0%)
ComEd	$35.75	$34.64	($1.11)	(3.2%)
DAY	$39.22	$38.69	($0.52)	(1.4%)
DLCO	$39.71	$39.65	($0.06)	(0.1%)
Dominion	$53.30	$49.43	($3.87)	(7.8%)
DPL	$51.32	$49.01	($2.30)	(4.7%)
JCPL	$51.09	$47.96	($3.13)	(6.5%)
Met-Ed	$50.23	$47.27	($2.96)	(6.3%)
PECO	$50.53	$47.54	($2.99)	(6.3%)
PENELEC	$44.51	$41.83	($2.67)	(6.4%)
Pepco	$54.23	$50.44	($3.79)	(7.5%)
PPL	$49.71	$46.66	($3.05)	(6.5%)
PSEG	$52.23	$49.91	($2.31)	(4.6%)
RECO	$50.69	$46.66	($4.02)	(8.6%)

Price Convergence by Jurisdiction

Table 2-79 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 2-90)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$50.73	$48.30	($2.43)	(5.0%)
Illinois	$35.75	$34.64	($1.11)	(3.2%)
Indiana	$38.60	$37.85	($0.75)	(2.0%)
Kentucky	$40.81	$40.21	($0.59)	(1.5%)
Maryland	$53.50	$50.18	($3.32)	(6.6%)
Michigan	$39.18	$38.54	($0.64)	(1.7%)
New Jersey	$51.73	$49.08	($2.65)	(5.4%)
North Carolina	$51.71	$48.01	($3.70)	(7.7%)
Ohio	$38.58	$38.04	($0.54)	(1.4%)
Pennsylvania	$47.48	$45.06	($2.42)	(5.4%)
Tennessee	$43.18	$41.90	($1.28)	(3.1%)
Virginia	$52.22	$48.59	($3.63)	(7.5%)
West Virginia	$40.63	$39.81	($0.82)	(2.1%)
District of Columbia	$54.58	$50.72	($3.87)	(7.6%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-80 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2009 to March 31, 2010 (See 2009 SOM, Table 2-91)

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	12.6%	15.4%	72.0%	11.9%	19.5%	68.6%	(0.8%)	4.2%	(3.4%)
Feb	13.4%	14.5%	72.1%	13.3%	19.5%	67.2%	(0.1%)	5.0%	(4.9%)
Mar	13.8%	16.7%	69.5%	12.6%	19.8%	67.6%	(1.2%)	3.1%	(1.9%)
Apr	13.5%	17.2%	69.3%						
May	14.6%	18.8%	66.7%						
Jun	12.5%	16.5%	71.0%						
Jul	12.6%	16.9%	70.5%						
Aug	11.7%	16.0%	72.3%						
Sep	12.5%	18.1%	69.4%						
Oct	13.0%	19.8%	67.2%						
Nov	13.2%	19.0%	67.8%						
Dec	11.7%	16.8%	71.5%						
Annual	12.9%	17.0%	70.1%	12.6%	19.6%	67.8%	(0.3%)	2.6%	(2.3%)

Day-Ahead Load and Spot Market

Table 2-81 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar years 2009 to March 31, 2010 (See 2009 SOM, Table 2-92)

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.4%	13.7%	81.9%	4.7%	19.4%	75.9%	0.3%	5.7%	(6.0%)
Feb	4.5%	12.3%	83.2%	5.1%	19.3%	75.5%	0.7%	7.0%	(7.7%)
Mar	4.3%	12.8%	82.9%	5.3%	19.4%	75.3%	0.9%	6.7%	(7.6%)
Apr	4.4%	13.8%	81.7%						
May	4.6%	15.6%	79.8%						
Jun	4.7%	13.9%	81.4%						
Jul	5.6%	16.0%	78.4%						
Aug	5.2%	15.3%	79.5%						
Sep	4.8%	16.1%	79.2%						
Oct	5.0%	17.8%	77.2%						
Nov	5.8%	15.9%	78.3%						
Dec	5.2%	15.6%	79.2%						
Annual	4.9%	14.9%	80.2%	5.0%	19.4%	75.6%	0.1%	4.5%	(4.7%)

Demand-Side Response (DSR)

PJM Load Response Programs Overview

Table 2-82 Overview of Demand Side Programs (See 2009 SOM, Table 2-93)

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
Registered ILR only	DR cleared in RPM; Registered ILR	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Voluntary Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for mandatory curtailments.	Energy payment based on LMP less generation component of retail rate. Energy payment for hours of voluntary curtailment.

Participation

Economic Program

Table 2-83 Economic Program registration on peak load days: Calendar years 2002 to 2009 and January through March 2010 (See 2009 SOM, Table 2-94)

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
03-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
02-Aug-06	253	1,100.7
08-Aug-07	2,897	2,498.0
09-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
04-Jan-10	1,852	2,625.0

Table 2-84 Economic Program registrations on the last day of the month: January 2007 through March 2010 (See 2009 SOM, Table 2-95)

	2007		2008		2009		2010	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	508	1,530	4,906	2,959	4,862	3,303	1,841	2,623
Feb	953	1,567	4,902	2,961	4,869	3,219	1,842	2,624
Mar	959	1,578	4,972	3,012	4,867	3,227	1,845	2,623
Apr	980	1,648	5,016	3,197	2,582	3,242		
May	996	3,674	5,069	3,588	1,250	2,860		
Jun	2,490	2,168	3,112	3,014	1,265	2,461		
Jul	2,872	2,459	4,542	3,165	1,265	2,445		
Aug	2,911	2,582	4,815	3,232	1,653	2,650		
Sep	4,868	2,915	4,836	3,263	1,879	2,727		
Oct	4,873	2,880	4,846	3,266	1,875	2,730		
Nov	4,897	2,948	4,851	3,271	1,874	2,730		
Dec	4,898	2,944	4,851	3,290	1,853	2,627		
Avg.	2,684	2,408	4,727	3,185	2,508	2,852		

Table 2-85 Distinct registrations and sites in the Economic Program: January 4, 2010[7] (See 2009 SOM, Table 2-96)

	Registrations	Sites	MW
AECO	37	42	18.5
AEP	47	47	220.7
AP	91	91	196.7
BGE	147	159	649.5
ComEd	773	774	459.4
DAY	10	10	14.2
DLCO	34	34	72.2
Dominion	100	100	231.0
DPL	66	75	132.1
JCPL	40	75	102.1
Met-Ed	47	47	75.1
PECO	159	186	137.6
PENELEC	42	42	31.6
Pepco	22	23	21.1
PPL	139	145	195.5
PSEG	94	159	66.5
RECO	4	9	1.3
Total	1,852	2,018	2,625.0

7 Effective July 1, 2009, PJM implemented a new eSuite application, Load Response System (eLRS) to serve as the interface for collecting and storing customer registration and settlement data. With the implementation of the LRS system, more detail is available on customer registrations and, as a result, there is an enhanced ability to capture multiple distinct locations aggregated to a single registration. The second column, "Sites", reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

Figure 2-23 Economic Program payments: Calendar years 2007[8] through 2009 and January through March 2010[9] (See 2009 SOM, Figure 2-24)

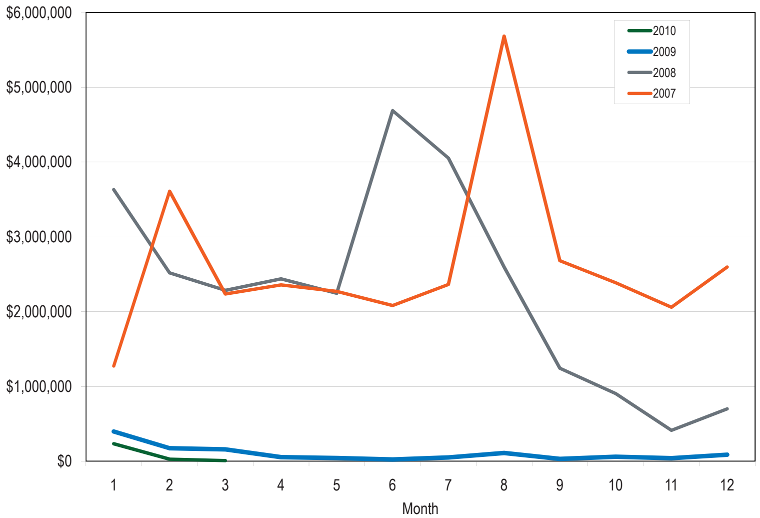


Table 2-86 PJM Economic Program by zonal reduction: January through March 2010 (See 2009 SOM, Table 2-99)

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO							0	$25	3	0	$25	3
AEP										0	$0	0
AP	1,039	$14,045	314				5	$806	1	1,044	$14,851	315
BGE										0	$0	0
ComEd	27	$1,105	28				319	$9,587	185	346	$10,692	213
DAY												
DLCO												
Dominion	2,272	$151,347	110	491	$7,566	70	255	$12,527	110	3,017	$171,439	290
DPL										0	$0	0
JCPL							8	$733	16	8	$733	16
Met-Ed	2	$16	8							2	$16	8
PECO	1,871	$54,485	4,190				78	$7,227	375	1,949	$61,712	4,565
PENELEC							1	$156	6	1	$156	6
Pepco							11	$270	57	11	$270	57
PPL	366	$8,622	244				12	$1,194	40	377	$9,815	284
PSEG										0	$0	0
RECO										0	$0	0
Total	5,576	$229,620	4,894	491	$7,566	70	689	$32,525	793	6,756	$269,710	5,757
Max	2,272	$151,347	4,190	491	$7,566	70	319	$12,527	375	3,017	$171,439	4,565
Avg	929	$38,270	816	491	$7,566	70	77	$3,614	88	450	$17,981	384

8 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 2-23 do not include these incentive payments.

9 March 2010 credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve settlements, which could account for a maximum of approximately 74 calendar days.

Table 2-87 Settlement days submitted by month in the Economic Program: January 2007 through March 2010 (See 2009 SOM, Table 2-100)

Month	2007	2008	2009	2010
Jan	937	2,916	1,264	1,423
Feb	1,170	2,811	654	546
Mar	1,255	2,818	574	411
Apr	1,540	3,406	337	
May	1,649	3,336	918	
Jun	1,856	3,184	2,727	
Jul	2,534	3,339	2,879	
Aug	3,962	3,848	3,760	
Sep	3,388	3,264	2,570	
Oct	3,508	1,977	2,361	
Nov	2,842	1,105	2,321	
Dec	2,675	986	1,240	
Total	26,423	32,990	21,605	2,380

Table 2-88 Distinct customers and CSPs submitting settlements in the Economic Program by month: January 2007 through March 2010 (See 2009 SOM, Table 2-101)

	2007		2008		2009		2010	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	11	72	13	261	17	257	11	162
Feb	10	89	13	243	12	129	9	92
Mar	9	87	11	216	11	149	7	124
Apr	11	98	12	208	9	76		
May	12	109	12	233	9	201		
Jun	12	195	17	317	20	231		
Jul	15	259	16	295	21	183		
Aug	19	321	17	306	15	400		
Sep	15	279	17	312	11	181		
Oct	11	245	13	226	11	93		
Nov	10	204	14	208	9	143		
Dec	11	243	13	193	10	160		
Total Distinct Active	21	405	24	522	25	747	12	167

Table 2-89 Hourly distribution of Economic Program MWh reductions and credits: January through March 2010 (See 2009 SOM, Table 2-102)

	MWh Reductions				Program Credits			
Hour	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	30	0.44%	30	0.44%	$429	0.16%	$429	0.16%
2	38	0.56%	68	1.00%	$408	0.15%	$837	0.31%
3	70	1.04%	138	2.04%	$1,012	0.38%	$1,849	0.69%
4	82	1.22%	220	3.26%	$2,319	0.86%	$4,168	1.55%
5	78	1.15%	298	4.40%	$1,034	0.38%	$5,202	1.93%
6	77	1.14%	374	5.54%	$1,163	0.43%	$6,365	2.36%
7	368	5.44%	742	10.98%	$23,760	8.81%	$30,124	11.17%
8	758	11.22%	1,500	22.20%	$56,168	20.83%	$86,293	31.99%
9	705	10.44%	2,205	32.64%	$35,903	13.31%	$122,195	45.31%
10	459	6.79%	2,664	39.43%	$19,749	7.32%	$141,944	52.63%
11	287	4.25%	2,951	43.68%	$8,999	3.34%	$150,943	55.96%
12	241	3.57%	3,192	47.25%	$7,100	2.63%	$158,043	58.60%
13	242	3.58%	3,434	50.83%	$5,632	2.09%	$163,674	60.69%
14	253	3.75%	3,687	54.58%	$5,515	2.04%	$169,189	62.73%
15	226	3.34%	3,913	57.92%	$3,494	1.30%	$172,684	64.03%
16	191	2.83%	4,104	60.75%	$2,505	0.93%	$175,189	64.95%
17	241	3.56%	4,345	64.31%	$3,841	1.42%	$179,029	66.38%
18	425	6.29%	4,770	70.60%	$16,948	6.28%	$195,977	72.66%
19	620	9.18%	5,390	79.78%	$26,583	9.86%	$222,561	82.52%
20	538	7.96%	5,928	87.74%	$21,601	8.01%	$244,161	90.53%
21	309	4.58%	6,237	92.32%	$15,256	5.66%	$259,418	96.18%
22	238	3.53%	6,475	95.85%	$5,895	2.19%	$265,313	98.37%
23	191	2.82%	6,666	98.67%	$2,969	1.10%	$268,281	99.47%
24	90	1.33%	6,756	100.00%	$1,429	0.53%	$269,710	100.00%

Table 2-90 Distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through March 2010 (See 2009 SOM, Table 2-103)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	7	0.11%	7	0.11%	$0	0.00%	$0	0.00%
$25 to $50	2,434	36.03%	2,441	36.14%	$26,670	9.89%	$26,670	9.89%
$50 to $75	1,490	22.06%	3,932	58.20%	$36,756	13.63%	$63,426	23.52%
$75 to $100	837	12.39%	4,769	70.59%	$35,563	13.19%	$98,989	36.70%
$100 to $125	728	10.77%	5,496	81.36%	$42,098	15.61%	$141,087	52.31%
$125 to $150	519	7.68%	6,016	89.04%	$27,607	10.24%	$168,694	62.55%
$150 to $200	402	5.95%	6,418	94.99%	$34,787	12.90%	$203,481	75.44%
$200 to $250	172	2.54%	6,589	97.54%	$29,826	11.06%	$233,307	86.50%
$250 to $300	81	1.20%	6,670	98.73%	$15,662	5.81%	$248,969	92.31%
> $300	86	1.27%	6,756	100.00%	$20,741	7.69%	$269,710	100.00%

Emergency Program

Table 2-91 Registered sites and MW in the Emergency Program[10] (By zone and option): January 4, 2010 (See 2009 SOM, Table 2-104)

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	131	45.7	12	15.9
AEP	0	0.0	588	1,259.9	99	504.3
AP	0	0.0	524	424.9	42	72.2
BGE	0	0.0	485	615.8	29	26.1
ComEd	0	0.0	805	646.6	526	697.1
DAY	0	0.0	159	147.5	13	57.2
DLCO	0	0.0	160	86.7	34	33.7
Dominion	0	0.0	444	469.2	46	40.6
DPL	0	0.0	169	127.2	15	39.5
JCPL	0	0.0	285	124.3	28	22.4
Met-Ed	0	0.0	174	182.3	42	42.2
PECO	0	0.0	414	136.5	235	215.3
PENELEC	0	0.0	248	192.7	45	27.6
Pepco	0	0.0	269	88.7	32	29.0
PPL	0	0.0	555	292.1	127	315.0
PSEG	0	0.0	582	286.8	79	26.0
RECO	0	0.0	15	3.0	6	0.5
Total	0	0.0	6,007	5,129.8	1,410	2,164.5

10 Table 2-90 shows registered sites and MW in the Emergency Program as of January 4, 2010, the peak load day through the first three months of 2010. As all resources are registered in either the Capacity Only or Full options, all resources in the Emergency Program are considered RPM Resources participating in the Load Management (LM) Program. Registered sites and MW remain constant in the LM Program through delivery years. For more information on LM Program participation and testing, see the *2009 State of the Market Report*, Section 2 – Energy Market, Part 1: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume2-sec2.pdf

SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for the first three months of 2010. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue quantifies the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Total fixed costs, in this sense, include all but short run variable costs.

  The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

- **Net Revenue and Total Fixed Costs.** When compared to total fixed costs, net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and in existing generation to serve PJM markets. Net revenue quantifies the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources when there is a market based need, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  In 2009, net revenues were not adequate to cover total fixed costs for a new entrant CT, CC or CP in any zone. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs, reflecting their greater reliance on capacity market revenues.

  In the first three months of 2010, net revenues are mixed compared to the same period in 2009. For the new entrant CT, thirteen zones had higher net revenue and four zones had lower net revenue compared to the same period in 2009. (Table 3-8.) For the CT, all zones except for DLCO had a decrease in energy net revenue. The twelve zones that were part of the EMAAC or SWMAAC Locational Delivery Areas (LDAs) for the 2009/2010 delivery year had higher capacity revenues, which more than offset lower energy revenues. The five zones that cleared in the unconstrained RTO LDA had lower capacity revenues. However, the increase in energy net revenue was greater than the decrease in capacity revenues for the DLCO control zone. For the new entrant CC, fourteen zones had a decrease in net revenue through March 2010 compared to the same period in 2009, while DLCO, PPL and PSEG had an increase. For the CC, like the CT, all zones except DLCO had a decrease in energy net revenue. For the zones that were part of the EMAAC and SWMAAC LDAs, the decrease in energy net revenue was greater than the increase in capacity revenues. In PPL and PSEG, the increase in capacity revenue was greater than the decrease in energy net revenues, while, in DLCO, higher energy net revenues were greater than the decrease in capacity revenue associated with the RTO LDA. For the new entrant coal plant (CP), eight zones had an increase in net revenue for January through March 2010 compared to the same period in 2009, while nine zones show a decrease. For the CP, changes in results from 2009 to 2010 were primarily a result of changes in energy market net revenues. Of the eight zones that had an increase in net revenue, seven had an increase in energy net revenues. The AP zone had a slight decrease in energy net revenue compared to the same period in 2009, which was more than offset by higher capacity revenue.

All nine zones that had a decrease in net revenue compared to the same period in 2009 also had a decrease in energy net revenue.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through March 31, 2010, PJM installed capacity resources fell slightly from 167,853.8 MW on January 1 to 167,794.8 MW on March 31, a decrease of 59 MW or 0.0 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of March 31, 2010, 40.7 percent was coal; 29.3 percent was natural gas; 18.2 percent was nuclear; 6.4 percent was oil; 4.7 percent was hydroelectric; 0.4 percent was solid waste, and 0.2 percent was wind.

- **Generation Fuel Mix.** During the first three months of 2010, coal provided 53.9 percent, nuclear 34.7 percent, gas 7.0 percent, oil 0.1 percent, hydroelectric 2.3 percent, solid waste 0.8 percent and wind 1.3 percent of total generation.

- **Planned Generation.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Scarcity

- **Scarcity Pricing Events in the first three months of 2010.** PJM did not declare a scarcity event in the first three months of 2010.

  Scarcity exists when demand plus reserve requirements approach the available generating capacity of the system. Scarcity pricing means that market prices reflect the fact that the system is using close to its available capacity and that competitive prices may exceed accounting short-run marginal costs. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail. As demand increases and units with higher offers are required to meet demand, prices increase.

- **Modifications to Scarcity Pricing.** PJM's scarcity pricing rules need refinement.

  The essential components of a new approach to scarcity pricing include: reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch; an appropriate operating reserve target, e.g. 10 minute synchronized reserves; accurate measurement of the operating reserve levels used as a scarcity trigger; an accurate and effective offset mechanism for RPM revenues; a rule governing the recall of the energy from capacity resources during scarcity events; and maintaining local market power mitigation mechanisms.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, operating reserve payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

- **Operating Reserve Charges in the First Three Months of 2010.** The level of operating reserve credits and corresponding charges increased in the first three months of 2010 by 8.3 percent compared to the first three months of 2009. High levels of congestion led to increases in balancing operating reserve credits in January and February. This increase was comprised of an 8.4 percent increase, or $6,142,769, in the amount of balancing operating reserve credits, and an increase of 16.4 percent, or $4,299,551, in day-ahead credits.

- **New Operating Reserve Rules.** New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. The MMU calculated the impact of the new operating reserve rules in three areas.

  The rule changes allocated an increased proportion of balancing operating reserve credits to real-time load and exports. The purpose of this rule change was to reallocate a portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, determined to be real-time load and exports. The new operating reserve rules resulted in an increase of $15,642,681 in charges assigned to real-time load and exports for the first three months of 2010. These increases were matched by a decrease of $7,973,883 in charges to demand deviations, a decrease of $5,297,882 in charges to supply deviations, and a decrease of $2,370,915 in charges to generator deviations.

  The rule changes resulted in a reduced allocation of charges to deviations, which reduced operating reserve payments assigned to virtual market activity. The net result is that virtual offers and bids paid $5,020,215 less in operating reserve charges as a result of the change in rules than they would have paid under the old rules. These charges were paid by real time load and exports.

  The rule changes included the introduction of segmented make whole payments, which results in a calculation of operating reserve credits for periods shorter than the 24 hours used under the old rules. As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $1,451,963, or 2.2 percent, higher for the first three months of 2010 than what would have been credited under the old rules.

- **Parameter Limited Schedule Rules.** On March 19, 2009, the Commission issued an order rejecting PJM's proposed revisions to Section 6.6(c) of Schedule 1 of the PJM Operating Agreement that would have altered the application of the rules for evaluating requests for exceptions to the values included in or derived on a formulaic basis from the Parameter Limited Schedule Matrix.[1] As a consequence, the business rules approved by the Members Committee on November 15, 2007, were reinstated. PJM and the Market Monitor jointly administered these rules for the spring cycle.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and

1 126 FERC ¶61,251 (2009).

capacity markets. With a capacity market design that appropriately reflects a direct and explicit offset for scarcity revenues in the energy market, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

PJM's RPM is an explicit effort to address these issues. RPM is a Capacity Market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market.

In the first three months of 2010, energy market revenues were generally lower for the two natural gas fired technologies, as energy market prices were lower in most zones while the average delivered price of natural gas in most zones stayed approximately the same or increased. Energy net revenues for the CP were mixed as many eastern zones showed a decrease compared to the same period in 2009, while several zones, including eastern and western zones, showed an increase. This reflects greater locational price separation in both energy market prices and input fuel prices compared to the prior period.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. Most zones had few high demand days and lower volatility through the first three months of 2010 compared to 2009, while the average on peak LMP in DLCO increased by 25.3 percent. As a result, most zones had a decrease in energy market net revenue while DLCO control zone had a 35 percent increase.

Scarcity revenues in the energy market contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the Capacity Market provides a significant stream of revenue that contributes to the recovery of avoidable costs for existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The Capacity Market is also a significant source of net revenue to cover the fixed costs of investing in new peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when energy net revenues available for new entrants decreases rapidly, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs.

Coal plants (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. When less efficient coal units are on the margin, net revenues are higher for more efficient coal units. Coal units also receive higher net revenue when CTs set price based on gas costs. For the period January through March 2010, with generally lower load levels, CTs ran less often, which reduced the net revenue received by coal plants.

Net Revenue

Capacity Market Net Revenue

Table 3-1 2010 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2010 (See 2009 SOM, Table 3-3)

	Delivery Year 2009/2010			Delivery Year 2010/2011			RPM Revenue
Zone	LDA	$/MW-Day	$/MW in 2010	LDA	$/MW-Day	$/MW in 2010	2010 (Jan - Dec) $/MW
AECO	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
AEP	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
AP	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
BGE	SWMAAC	$237.33	$35,837		$174.29	$37,298	$73,135
ComEd	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
DAY	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
DLCO	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
Dominion	RTO	$102.04	$15,408		$174.29	$37,298	$52,706
DPL	MAAC+APS	$191.32	$28,889	DPL-SOUTH	$186.12	$39,830	$68,719
JCPL	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
Met-Ed	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PECO	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PENELEC	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
Pepco	SWMAAC	$237.33	$35,837		$174.29	$37,298	$73,135
PPL	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PSEG	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
RECO	MAAC+APS	$191.32	$28,889		$174.29	$37,298	$66,187
PJM	NA	$138.46	$20,907	NA	$174.42	$37,327	$58,234

Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-4)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$13,392	$17,219	29%
AEP	$10,073	$9,184	(9%)
AP	$10,073	$17,219	71%
BGE	$18,910	$21,360	13%
ComEd	$10,073	$9,184	(9%)
DAY	$10,073	$9,184	(9%)
DLCO	$10,073	$9,184	(9%)
Dominion	$10,073	$9,184	(9%)
DPL	$13,392	$17,219	29%
JCPL	$13,392	$17,219	29%
Met-Ed	$10,073	$17,219	71%
PECO	$13,392	$17,219	29%
PENELEC	$10,073	$17,219	71%
Pepco	$18,910	$21,360	13%
PPL	$10,073	$17,219	71%
PSEG	$13,392	$17,219	29%
RECO	$13,392	$17,219	29%
PJM	$11,212	$12,461	11%

New Entrant Net Revenues

Table 3-3 Average delivered fuel price in PJM[2] (Dollars per MBtu): January through March 2009 and 2010 (See 2009 SOM, Table 3-5)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
Natural Gas	$6.38	$6.44	1%
Low Sulfur Coal	$3.54	$3.03	(14%)

Table 3-4 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[3]: Net revenue for January through March 2009 and 2010 (See 2009 SOM, Table 3-6)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$3,894	$1,821	(53%)
AEP	$1,739	$1,020	(41%)
AP	$5,998	$2,250	(62%)
BGE	$3,984	$3,287	(17%)
ComEd	$963	$454	(53%)
DAY	$1,242	$822	(34%)
DLCO	$790	$3,888	392%
Dominion	$4,981	$4,186	(16%)
DPL	$5,090	$2,522	(50%)
JCPL	$3,857	$2,177	(44%)
Met-Ed	$3,524	$1,905	(46%)
PECO	$3,372	$1,908	(43%)
PENELEC	$2,973	$957	(68%)
Pepco	$8,494	$7,012	(17%)
PPL	$3,406	$1,794	(47%)
PSEG	$2,661	$2,270	(15%)
RECO	$2,090	$1,432	(32%)
PJM	$3,474	$2,336	(33%)

Table 3-5 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for January through March 2009 and 2010 (See 2009 SOM, Table 3-7)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$16,130	$10,129	(37%)
AEP	$8,227	$5,132	(38%)
AP	$19,453	$10,204	(48%)
BGE	$15,418	$12,685	(18%)
ComEd	$6,758	$2,843	(58%)
DAY	$7,596	$4,870	(36%)
DLCO	$5,806	$7,860	35%
Dominion	$17,573	$12,881	(27%)
DPL	$17,545	$11,295	(36%)
JCPL	$16,634	$10,989	(34%)
Met-Ed	$14,468	$10,197	(30%)
PECO	$14,625	$10,362	(29%)
PENELEC	$14,601	$6,835	(53%)
Pepco	$24,507	$19,487	(20%)
PPL	$14,091	$9,454	(33%)
PSEG	$13,979	$10,839	(22%)
RECO	$11,995	$7,676	(36%)
PJM	$14,083	$9,632	(32%)

2 The average delivered fuel prices shown in Table 3-3 are included for illustrative purposes, represent single indices and do not represent a PJM aggregate fuel price. Most natural gas and coal price indices followed similar trends. However, actual delivered fuel prices varied significantly by location in the first three months of 2010.

3 The energy net revenues presented for "PJM" for the periods January through March 2009 and 2010 in this section represent the simple average of all zonal energy net revenues. Similarly, the total net revenues presented for "PJM" represent the simple average energy net revenue.

Table 3-6 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for January through March 2009 and 2010 (See 2009 SOM, Table 3-8)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$46,220	$33,276	(28%)
AEP	$12,415	$17,770	43%
AP	$29,721	$25,452	(14%)
BGE	$28,728	$33,776	18%
ComEd	$15,980	$25,343	59%
DAY	$12,746	$18,874	48%
DLCO	$13,371	$27,913	109%
Dominion	$29,173	$34,622	19%
DPL	$27,466	$31,177	14%
JCPL	$43,613	$32,246	(26%)
Met-Ed	$38,505	$30,561	(21%)
PECO	$43,038	$31,814	(26%)
PENELEC	$32,028	$20,936	(35%)
Pepco	$38,662	$36,129	(7%)
PPL	$41,848	$30,188	(28%)
PSEG	$42,672	$35,944	(16%)
RECO	$42,095	$30,042	(29%)
PJM	$31,664	$29,180	(8%)

New Entrant Combustion Turbine

Table 3-7 Real-time PJM average net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through March 2010 (See 2009 SOM, Table 3-9)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
Energy	$3,474	$2,336	(33%)
Capacity	$9,992	$11,234	12%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$600	$600	0%
Total	$14,066	$14,169	1%

Table 3-8 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-10)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$16,428	$17,944	9%
AEP	$11,316	$9,899	(13%)
AP	$15,575	$18,373	18%
BGE	$21,435	$23,143	8%
ComEd	$10,539	$9,333	(11%)
DAY	$10,818	$9,701	(10%)
DLCO	$10,367	$12,767	23%
Dominion	$14,557	$13,065	(10%)
DPL	$17,624	$18,645	6%
JCPL	$16,391	$18,301	12%
Met-Ed	$13,101	$18,028	38%
PECO	$15,906	$18,031	13%
PENELEC	$12,549	$17,080	36%
Pepco	$25,945	$26,868	4%
PPL	$12,982	$17,917	38%
PSEG	$15,195	$18,393	21%
RECO	$14,625	$17,555	20%
PJM	$14,066	$14,169	1%

New Entrant Combined Cycle

Table 3-9 Real-time PJM average net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through March 2010 (See 2009 SOM, Table 3-11)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
Energy	$14,083	$9,632	(32%)
Capacity	$10,832	$11,986	11%
Synchronized	$0	$0	0%
Regulation	$0	$0	0%
Reactive	$800	$800	0%
Total	$25,714	$22,418	(13%)

Table 3-10 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-12)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$29,867	$27,491	(8%)
AEP	$18,758	$14,766	(21%)
AP	$29,984	$27,567	(8%)
BGE	$34,486	$34,031	(1%)
ComEd	$17,289	$12,476	(28%)
DAY	$18,127	$14,503	(20%)
DLCO	$16,337	$17,494	7%
Dominion	$28,104	$22,515	(20%)
DPL	$31,282	$28,658	(8%)
JCPL	$30,371	$28,352	(7%)
Met-Ed	$24,999	$27,559	10%
PECO	$28,362	$27,725	(2%)
PENELEC	$25,131	$24,197	(4%)
Pepco	$43,575	$40,832	(6%)
PPL	$24,622	$26,816	9%
PSEG	$27,717	$28,201	2%
RECO	$25,732	$25,039	(3%)
PJM	$25,714	$22,418	(13%)

New Entrant Coal Plant

Table 3-11 Real-time PJM average net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): January through March 2010 (See 2009 SOM, Table 3-13)

	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
Energy	$31,664	$29,180	(8%)
Capacity	$10,108	$11,301	12%
Synchronized	$0	$0	0%
Regulation	$82	$33	(59%)
Reactive	$446	$446	0%
Total	$42,300	$40,960	(3%)

Table 3-12 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-14)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$58,740	$49,366	(16%)
AEP	$21,942	$26,592	21%
AP	$39,248	$41,554	6%
BGE	$46,222	$53,618	16%
ComEd	$25,507	$34,208	34%
DAY	$22,273	$27,704	24%
DLCO	$22,898	$36,765	61%
Dominion	$38,700	$43,423	12%
DPL	$39,986	$47,270	18%
JCPL	$56,132	$48,337	(14%)
Met-Ed	$48,032	$46,654	(3%)
PECO	$55,558	$47,904	(14%)
PENELEC	$41,555	$37,040	(11%)
Pepco	$56,156	$55,971	(0%)
PPL	$51,375	$46,281	(10%)
PSEG	$55,191	$52,033	(6%)
RECO	$54,614	$46,136	(16%)
PJM	$42,300	$40,960	(3%)

New Entrant Day-Ahead Net Revenues

Table 3-13 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-15)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$2,039	$547	(73%)
AEP	$638	$110	(83%)
AP	$2,830	$805	(72%)
BGE	$2,227	$1,040	(53%)
ComEd	$105	$6	(94%)
DAY	$236	$25	(89%)
DLCO	$80	$340	326%
Dominion	$3,178	$2,408	(24%)
DPL	$2,754	$614	(78%)
JCPL	$1,780	$588	(67%)
Met-Ed	$1,653	$575	(65%)
PECO	$1,747	$592	(66%)
PENELEC	$1,795	$320	(82%)
Pepco	$6,797	$5,717	(16%)
PPL	$1,554	$561	(64%)
PSEG	$1,074	$312	(71%)
RECO	$705	$220	(69%)
PJM	$1,835	$869	(53%)

Table 3-14 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-16)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$15,495	$9,827	(37%)
AEP	$6,623	$4,793	(28%)
AP	$16,835	$10,475	(38%)
BGE	$15,287	$13,596	(11%)
ComEd	$4,098	$2,039	(50%)
DAY	$5,070	$3,794	(25%)
DLCO	$3,299	$5,773	75%
Dominion	$17,655	$15,489	(12%)
DPL	$16,605	$10,132	(39%)
JCPL	$16,044	$11,920	(26%)
Met-Ed	$13,788	$10,505	(24%)
PECO	$14,470	$10,908	(25%)
PENELEC	$13,681	$8,525	(38%)
Pepco	$25,134	$22,605	(10%)
PPL	$13,296	$9,894	(26%)
PSEG	$13,186	$9,625	(27%)
RECO	$11,237	$7,885	(30%)
PJM	$13,047	$9,870	(24%)

Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-17)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	Percent Change
AECO	$48,583	$38,319	(21%)
AEP	$11,316	$18,595	64%
AP	$28,088	$28,055	(0%)
BGE	$32,085	$40,269	26%
ComEd	$15,906	$27,080	70%
DAY	$10,866	$19,194	77%
DLCO	$10,767	$27,875	159%
Dominion	$31,379	$41,602	33%
DPL	$28,578	$35,399	24%
JCPL	$46,173	$38,095	(17%)
Met-Ed	$40,862	$36,011	(12%)
PECO	$46,274	$37,424	(19%)
PENELEC	$32,808	$25,651	(22%)
Pepco	$41,984	$43,273	3%
PPL	$43,994	$35,836	(19%)
PSEG	$45,005	$40,338	(10%)
RECO	$44,385	$37,307	(16%)
PJM	$32,886	$33,548	2%

Table 3-16 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar year 2000 to 2009 and January through March 2010 (See 2009 SOM, Table 3-18)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,183	62%
2008	$12,442	$6,623	$5,819	47%
2009	$5,113	$1,966	$3,148	62%
2010 (Jan - Mar)	$2,336	$869	$1,466	63%

Table 3-17 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar year 2000 to 2009 and January through March 2010 (See 2009 SOM, Table 3-19)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,631	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,196	20%
2006	$44,692	$31,670	$13,023	29%
2007	$66,616	$44,434	$22,183	33%
2008	$62,039	$47,342	$14,697	24%
2009	$31,581	$28,360	$3,221	10%
2010 (Jan - Mar)	$9,632	$9,870	($238)	(2%)

Table 3-18 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar year 2000 to 2009 and January through March 2010 (See 2009 SOM, Table 3-20)

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,159)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,374)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,571	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,267	3%
2009	$49,022	$45,844	$3,178	6%
2010 (Jan - Mar)	$29,180	$33,548	($4,368)	(15%)

Net Revenue Adequacy

Table 3-19 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year)) (See 2009 SOM, Table 3-21)

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Levelized Fixed Cost	2009 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640	$128,705
CC	$93,549	$99,230	$143,600	$171,361	$173,174
CP	$208,247	$267,792	$359,750	$492,780	$446,550

Table 3-20 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-23)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$16,428	$17,944	$128,705	13%	14%
AEP	$11,316	$9,899	$128,705	9%	8%
AP	$15,575	$18,373	$128,705	12%	14%
BGE	$21,435	$23,143	$128,705	17%	18%
ComEd	$10,539	$9,333	$128,705	8%	7%
DAY	$10,818	$9,701	$128,705	8%	8%
DLCO	$10,367	$12,767	$128,705	8%	10%
Dominion	$14,557	$13,065	$128,705	11%	10%
DPL	$17,624	$18,645	$128,705	14%	14%
JCPL	$16,391	$18,301	$128,705	13%	14%
Met-Ed	$13,101	$18,028	$128,705	10%	14%
PECO	$15,906	$18,031	$128,705	12%	14%
PENELEC	$12,549	$17,080	$128,705	10%	13%
Pepco	$25,945	$26,868	$128,705	20%	21%
PPL	$12,982	$17,917	$128,705	10%	14%
PSEG	$15,195	$18,393	$128,705	12%	14%
RECO	$14,625	$17,555	$128,705	11%	14%
PJM	$14,066	$14,169	$128,705	11%	11%

Figure 3-1 New entrant CT real-time 2009 and 2010 net revenue for January through March and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-3)

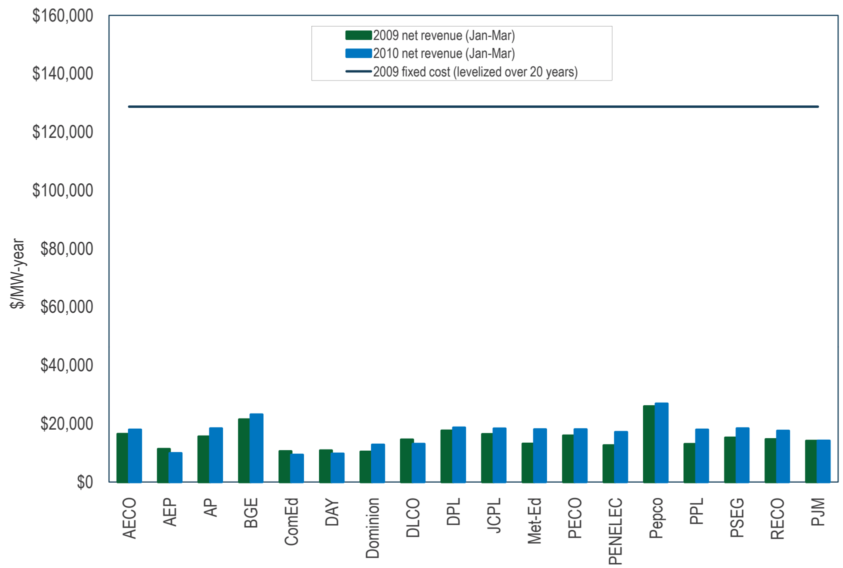


Table 3-21 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-25)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$29,867	$27,491	$173,174	17%	16%
AEP	$18,758	$14,766	$173,174	11%	9%
AP	$29,984	$27,567	$173,174	17%	16%
BGE	$34,486	$34,031	$173,174	20%	20%
ComEd	$17,289	$12,476	$173,174	10%	7%
DAY	$18,127	$14,503	$173,174	10%	8%
DLCO	$16,337	$17,494	$173,174	9%	10%
Dominion	$28,104	$22,515	$173,174	16%	13%
DPL	$31,282	$28,658	$173,174	18%	17%
JCPL	$30,371	$28,352	$173,174	18%	16%
Met-Ed	$24,999	$27,559	$173,174	14%	16%
PECO	$28,362	$27,725	$173,174	16%	16%
PENELEC	$25,131	$24,197	$173,174	15%	14%
Pepco	$43,575	$40,832	$173,174	25%	24%
PPL	$24,622	$26,816	$173,174	14%	15%
PSEG	$27,717	$28,201	$173,174	16%	16%
RECO	$25,732	$25,039	$173,174	15%	14%
PJM	$25,714	$22,418	$173,174	15%	13%

Figure 3-2 New entrant CC real-time 2009 and 2010 net revenue for January through March and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-5)

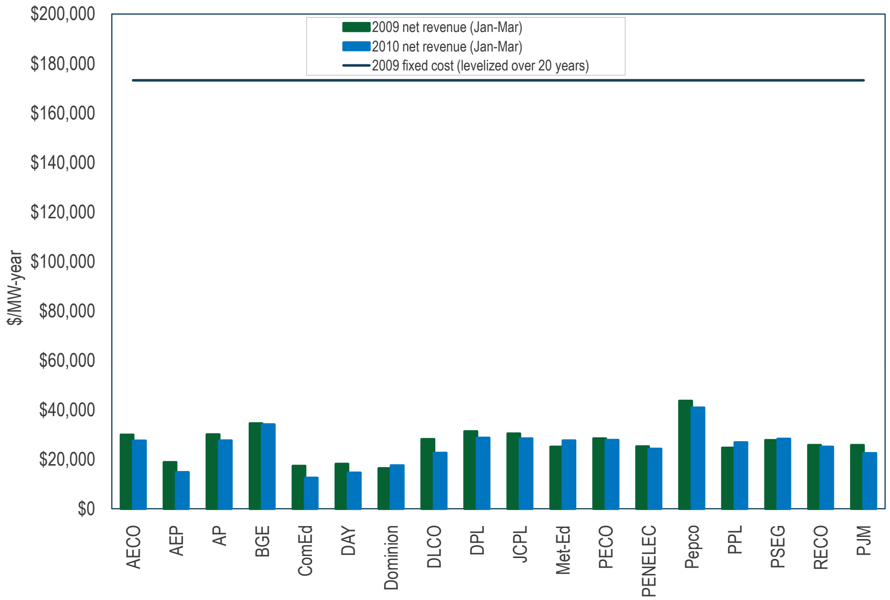
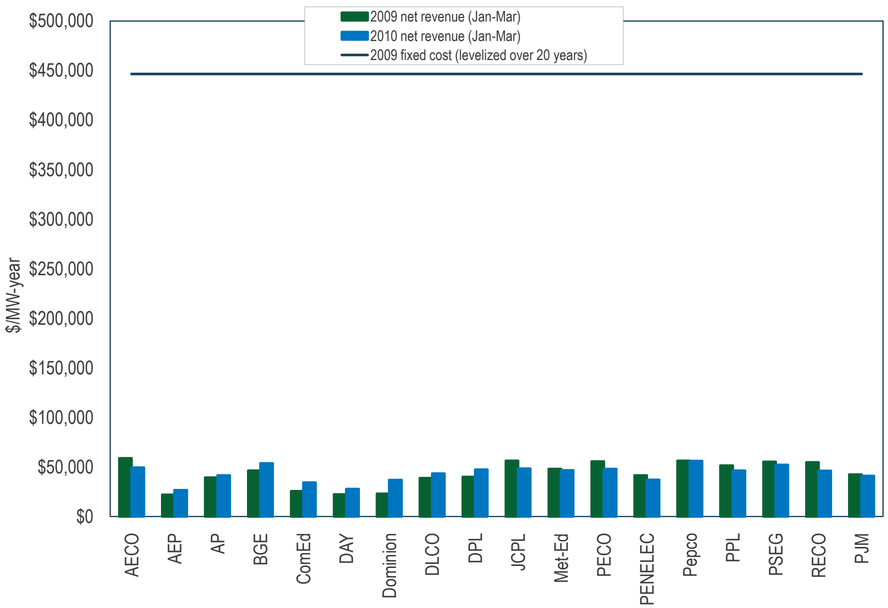


Table 3-22 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): January through March 2009 and 2010 (See 2009 SOM, Table 3-27)

Zone	2009 (Jan - Mar)	2010 (Jan - Mar)	20-Year Levelized Fixed Cost	2009 Percent Recovery	2010 Percent Recovery
AECO	$58,740	$49,366	$446,550	13%	11%
AEP	$21,942	$26,592	$446,550	5%	6%
AP	$39,248	$41,554	$446,550	9%	9%
BGE	$46,222	$53,618	$446,550	10%	12%
ComEd	$25,507	$34,208	$446,550	6%	8%
DAY	$22,273	$27,704	$446,550	5%	6%
DLCO	$22,898	$36,765	$446,550	5%	8%
Dominion	$38,700	$43,423	$446,550	9%	10%
DPL	$39,986	$47,270	$446,550	9%	11%
JCPL	$56,132	$48,337	$446,550	13%	11%
Met-Ed	$48,032	$46,654	$446,550	11%	10%
PECO	$55,558	$47,904	$446,550	12%	11%
PENELEC	$41,555	$37,040	$446,550	9%	8%
Pepco	$56,156	$55,971	$446,550	13%	13%
PPL	$51,375	$46,281	$446,550	12%	10%
PSEG	$55,191	$52,033	$446,550	12%	12%
RECO	$54,614	$46,136	$446,550	12%	10%
PJM	$42,300	$40,960	$446,550	9%	9%

Figure 3-3 New entrant CP real-time 2009 and 2010 net revenue for January through March and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year) (See 2009 SOM, Figure 3-7)



Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

Table 3-23 PJM installed capacity (By fuel source): January 1, January 31, February 28, and March 31, 2010 (See 2009 SOM, Table 3-35)

	1-Jan-10		31-Jan-10		28-Feb-10		31-Mar-10	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	68,382.1	40.7%	68,420.1	40.8%	68,273.2	40.7%	68,273.2	40.7%
Gas	49,238.8	29.3%	49,238.8	29.3%	49,234.0	29.4%	49,243.2	29.3%
Hydroelectric	7,921.9	4.7%	7,921.9	4.7%	7,897.9	4.7%	7,897.9	4.7%
Nuclear	30,611.9	18.2%	30,611.9	18.2%	30,599.9	18.2%	30,599.9	18.2%
Oil	10,700.1	6.4%	10,700.1	6.4%	10,699.0	6.4%	10,699.0	6.4%
Solid waste	672.1	0.4%	672.1	0.4%	672.1	0.4%	672.1	0.4%
Wind	326.9	0.2%	326.9	0.2%	338.9	0.2%	409.5	0.2%
Total	167,853.8	100.0%	167,891.8	100.0%	167,715.0	100.0%	167,794.8	100.0%

Energy Production by Fuel Source

Table 3-24 PJM generation (By fuel source (GWh)): January through March 2010 (See 2009 SOM, Table 3-36)

	GWh	Percent
Coal	98,548.0	53.9%
Nuclear	63,428.4	34.7%
Gas	12,817.2	7.0%
Natural Gas	12,432.7	6.8%
Landfill Gas	384.5	0.2%
Biomass Gas	0.1	0.0%
Hydroelectric	4,266.2	2.3%
Waste	1,403.6	0.8%
Solid Waste	1,069.4	0.6%
Miscellaneous	334.1	0.2%
Wind	2,336.4	1.3%
Oil	113.4	0.1%
Heavy Oil	80.6	0.0%
Light Oil	28.4	0.0%
Diesel	4.2	0.0%
Kerosene	0.2	0.0%
Jet Oil	0.0	0.0%
Solar	0.8	0.0%
Battery	0.1	0.0%
Total	182,914.1	100.0%

Planned Generation Additions

Table 3-25 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through March 2010[4] (See 2009 SOM, Table 3-37)

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	830

PJM Generation Queues

Table 3-26 Queue comparison (MW): March 31, 2010 vs. December 31, 2009 (See 2009 SOM, Table 3-38)

	MW in the Queue 2009	MW in the Queue 2010	Year-to-Year Change (MW)	Year-to-Year Change
2010	22,734	20,181	(2,553)	(13%)
2011	15,873	15,544	(330)	(2%)
2012	11,053	11,947	894	7%
2013	6,350	8,781	2,431	28%
2014	13,439	12,790	(649)	(5%)
2015	3,091	2,958	(133)	(4%)
2016	950	1,350	400	30%
2017	1,640	1,640	0	0%
2018	1,594	1,594	0	0%
Total	76,725	76,785	60	0%

4 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-27 Capacity in PJM queues (MW): At March 31, 2010[5, 6] (See 2009 SOM, Table 3-39)

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
B Expired 31-Jan-99	0	4,671	0	15,833	20,503
C Expired 31-Jul-99	0	531	0	4,151	4,682
D Expired 31-Jan-00	0	851	0	7,603	8,454
E Expired 31-Jul-00	0	795	0	16,887	17,682
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	21,986	23,102
H Expired 31-Jan-02	0	603	100	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,738	3,841
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	128	100	2,416	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	0	3,978	4,482
N Expired 31-Jan-05	1,377	2,133	223	6,663	10,397
O Expired 31-Jul-05	1,978	1,048	444	4,104	7,574
P Expired 31-Jan-06	931	989	1,799	4,768	8,486
Q Expired 31-Jul-06	2,245	707	3,583	8,133	14,668
R Expired 31-Jan-07	6,509	667	689	14,976	22,840
S Expired 31-Jul-07	7,526	967	1,321	11,079	20,892
T Expired 31-Jan-08	15,586	174	342	12,367	28,468
U Expired 31-Jan-09	12,136	110	464	22,151	34,861
V Expired 31-Jan-10	14,931	0	94	2,016	17,041
W Expires 31-Jan-11	3,759	0	0	0	3,759
Total	66,997	23,916	9,788	196,569	297,271

Table 3-28 Average project queue times: At March 31, 2010 (See 2009 SOM, Table 3-40)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	900	618	0	2,803
In-Service	738	638	0	3,287
Suspended	2,299	822	890	4,172
Under Construction	1,189	896	0	4,370
Withdrawn	492	478	0	2,793

5 The *2010 Quarterly State of the Market Report for PJM: January through March* contains all projects in the queue including reratings of existing generating units and energy only resources.
6 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Distribution of Units in the Queues

Table 3-29 Capacity additions in active or under-construction queues by control zone (MW): At March 31, 2010[7] (See 2009 SOM, Table 3-41)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
AECO	0	10	767	2	0	0	493	665	1,066	0	3,002
AEP	2	1,855	594	5	100	84	56	2,691	11,585	0	16,973
AP	0	958	4	19	68	0	310	774	1,388	0	3,522
BGE	0	0	0	6	0	1,640	0	132	0	25	1,803
ComEd	0	1,680	1,044	98	0	804	0	1,366	24,068	0	29,060
DAY	0	0	10	2	112	0	23	12	1,199	0	1,357
DLCO	0	0	0	0	0	91	0	0	0	0	91
DPL	14	0	55	0	0	0	120	43	450	0	682
Dominion	0	2,691	656	25	30	1,944	130	405	690	0	6,570
JCPL	0	1,430	27	33	0	0	113	0	0	0	1,603
Met-Ed	20	1,445	8	31	0	24	50	10	0	0	1,588
PECO	0	1,775	35	6	0	500	21	18	0	0	2,355
PENELEC	0	0	65	14	32	0	18	50	1,251	0	1,430
Pepco	20	2,670	249	0	0	0	0	0	0	0	2,939
PPL	0	0	128	8	143	1,600	38	116	179	11	2,222
PSEG	0	690	767	10	0	0	120	0	0	0	1,587
Total	56	15,203	4,409	259	485	6,687	1,492	6,281	41,877	36	76,785

Table 3-30 Capacity additions in active or under-construction queues by LDA (MW): At March 31, 2010[8] (See 2009 SOM, Table 3-42)

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	14	3,905	1,651	51	0	500	867	726	1,516	0	9,230
SWMAAC	20	2,670	249	6	0	1,640	0	132	0	25	4,742
WMAAC	20	1,445	201	53	175	1,624	106	176	1,430	11	5,240
RTO	2	7,184	2,308	149	310	2,923	519	5,248	38,931	0	57,574
Total	56	15,203	4,409	259	485	6,687	1,492	6,281	41,877	36	76,785

7 In this section, unit type "Unknown" is referred to for units that the RTEP has not yet identified.
8 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 3-31 Existing PJM capacity: At March 31, 2010[9] (By zone and unit type (MW)) (See 2009 SOM, Table 3-43)

	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
AECO	0	641	0	23	0	0	1,274	0	8	1,945
AEP	0	3,627	4,355	57	1,001	2,106	21,255	0	802	33,204
AP	0	1,140	1,129	36	108	0	7,974	0	431	10,818
BGE	0	862	0	7	0	1,735	3,039	0	0	5,643
ComEd	0	7,217	1,836	111	0	10,336	7,094	0	1,765	28,359
DAY	0	1,377	0	53	0	0	3,551	0	0	4,981
DLCO	0	188	101	0	6	1,741	1,259	0	0	3,295
DPL	0	2,487	364	95	0	0	2,016	0	0	4,962
Dominion	0	3,786	3,216	162	3,325	3,425	8,479	0	0	22,393
External	0	1,890	974	0	0	439	10,064	0	185	13,552
JCPL	0	1,430	1,196	25	400	615	318	0	0	3,983
Met-Ed	0	407	2,000	24	20	786	890	0	0	4,127
PECO	1	833	2,540	7	1,642	4,488	2,129	3	0	11,643
PENELEC	0	287	0	47	521	0	6,830	0	447	8,131
Pepco	0	1,571	0	12	0	0	4,707	0	0	6,290
PPL	0	1,362	960	63	571	2,275	5,530	0	217	10,977
PSEG	0	2,852	2,921	0	5	3,553	2,531	10	0	11,872
Total	1	31,955	21,592	723	7,599	31,499	88,938	13	3,854	186,173

9 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-32 PJM capacity age: At March 31, 2010 (MW) (See 2009 SOM, Table 3-44)

Age (years)	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	17,357	18,861	390	10	0	2,107	13	3,854	42,592
10 to 20	0	3,976	4,767	129	49	0	6,133	0	0	15,053
20 to 30	0	158	437	38	3,207	15,981	9,999	0	0	29,819
30 to 40	0	101	5,296	39	451	14,903	31,316	0	0	52,106
40 to 50	0	0	2,594	123	2,470	615	24,269	0	0	30,071
50 to 60	0	0	0	4	348	0	13,610	0	0	13,962
60 to 70	0	0	0	0	32	0	1,357	0	0	1,389
70 to 80	0	0	0	0	314	0	149	0	0	463
80 to 90	0	0	0	0	486	0	0	0	0	486
90 to 100	0	0	0	0	200	0	0	0	0	200
100 and over	0	0	0	0	32	0	0	0	0	32
Total	1	21,592	31,955	723	7,599	31,499	88,938	13	3,854	186,173

Table 3-33 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[10] (See 2009 SOM, Table 3-45)

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Battery	0	0.0%	1	0.0%	14	15	0.0%
	Combined Cycle	0	0.0%	7,021	20.4%	3,905	10,926	28.9%
	Combustion Turbine	960	12.1%	8,242	24.0%	1,651	8,933	23.7%
	Diesel	49	0.6%	150	0.4%	51	152	0.4%
	Hydroelectric	2,042	25.8%	2,047	5.9%	0	2,047	5.4%
	Nuclear	615	7.8%	8,656	25.2%	500	8,541	22.6%
	Solar	0	0.0%	13	0.0%	867	880	2.3%
	Steam	4,243	53.6%	8,268	24.0%	726	4,750	12.6%
	Wind	0	0.0%	8	0.0%	1,516	1,524	4.0%
	EMAAC Total	7,909	100.0%	34,405	100.0%	9,230	37,768	100.0%

Table continued next page

10 Percents shown in Table 3-33 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

(cont'd) Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
SWMAAC	Battery	0	0.0%	0	0.0%	20	20	0.2%
	Combined Cycle	0	0.0%	0	0.0%	2,670	2,670	20.8%
	Combustion Turbine	556	14.5%	2,433	20.4%	249	2,126	16.6%
	Diesel	0	0.0%	19	0.2%	6	25	0.2%
	Nuclear	0	0.0%	1,735	14.5%	1,640	3,375	26.3%
	Steam	3,266	85.5%	7,746	64.9%	132	4,612	35.9%
	Unknown	0	0.0%	0	0.0%	25	25	0.2%
	SWMAAC Total	3,822	100.0%	11,932	100.0%	4,743	12,834	100.0%
WMAAC	Battery	0	0.0%	0	0.0%	20	20	0.1%
	Combined Cycle	0	0.0%	2,960	12.7%	1,445	4,405	20.0%
	Combustion Turbine	296	4.3%	2,055	8.8%	201	1,960	8.9%
	Diesel	35	0.5%	135	0.6%	53	152	0.7%
	Hydroelectric	444	6.5%	1,112	4.8%	175	1,286	5.8%
	Nuclear	0	0.0%	3,061	13.2%	1,624	4,685	21.2%
	Solar	0	0.0%	0	0.0%	106	106	0.5%
	Steam	6,052	88.6%	13,249	57.0%	176	7,373	33.4%
	Wind	0	0.0%	663	2.9%	1,430	2,094	9.5%
	Unknown	0	0.0%	0	0.0%	11	11	0.1%
	WMAAC Total	6,827	100.0%	23,235	100.0%	5,240	22,061	100.0%
RTO	Battery	0	0.0%	0	0.0%	2	2	0.0%
	Combined Cycle	0	0.0%	11,611	10.0%	7,184	18,794	12.9%
	Combustion Turbine	782	2.8%	19,225	16.5%	2,308	20,751	14.2%
	Diesel	43	0.2%	419	0.4%	149	526	0.4%
	Hydroelectric	1,396	5.0%	4,440	3.8%	310	3,354	2.3%
	Nuclear	0	0.0%	18,047	15.5%	2,923	20,970	14.4%
	Solar	0	0.0%	0	0.0%	519	519	0.4%
	Steam	25,824	92.1%	59,676	51.2%	5,248	39,100	26.8%
	Wind	0	0.0%	3,183	2.7%	38,931	42,114	28.8%
	RTO Total	28,045	100.0%	116,601	100.0%	57,574	146,127	100.0%
All Areas	Total	46,602		186,173		76,785	218,789	

Characteristics of Wind Units

Table 3-34 Capacity factor of wind units in PJM, January through March 2010[11] (See 2009 SOM, Table 3-46)

Type of Resource	Capacity Factor	Total Hours	Installed Capacity (MW)
Energy-Only Resource	27.6%	31,351	1,336
Capacity Resource	34.4%	57,925	2,517
All Units	32.4%	89,276	3,854

Table 3-35 Wind resources in real time offering at a negative price in PJM, January through March 2010 (See 2009 SOM, Table 3-47)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	491.8	388	1.50%
All Wind	1,343.7	588	2.27%

Figure 3-4 Average hourly real-time generation of wind units in PJM, January through March 2010 (See 2009 SOM, Figure 3-11)

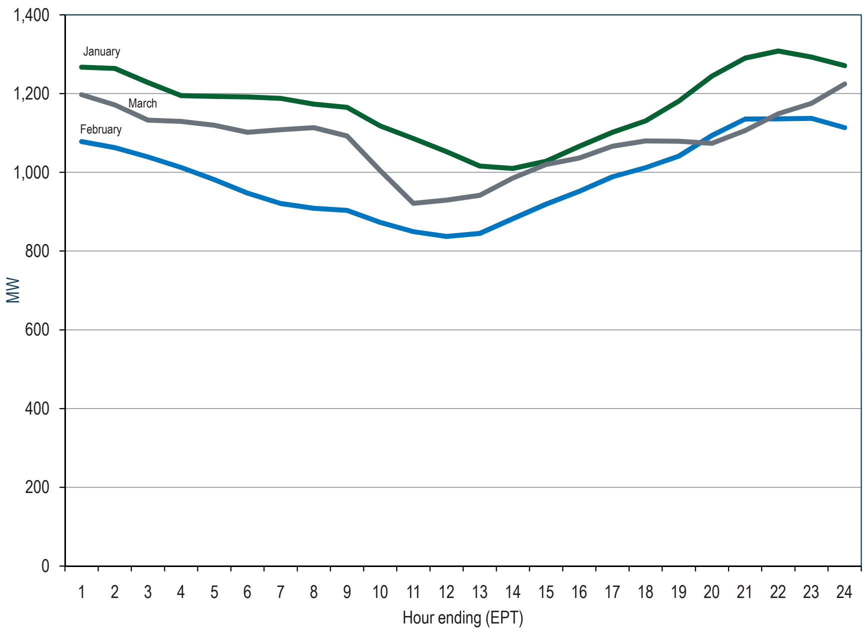


Table 3-36 Capacity factor of wind units in PJM by month, January through March 2010[12] (See 2009 SOM, Table 3-48)

Month	Generation (MWh)	Capacity Factor
January	869,954.9	36.9%
February	662,787.4	29.4%
March	803,642.1	31.0%
April		
May		
June		
July		
August		
September		
October		
November		
December		
Annual	2,336,384.4	32.4%

Table 3-37 Peak and off-peak seasonal capacity factor, average wind generation, and PJM load, January through March 2010 (See 2009 SOM, Table 3-49)

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	33.3%	27.2%			31.0%
	Average Wind Generation	1,086.7	950.8			1,037.1
	Average Load	91,305.2	78,083.9			86,478.4
Off-Peak	Capacity Factor	33.1%	34.7%			33.6%
	Average Wind Generation	1,078.9	1,210.0			1,121.6
	Average Load	80,380.7	66,406.2			75,827.7

11 The corresponding table in the *2009 Quarterly State of the Market Report for PJM: January through June*, reversed the labels for energy only resources and capacity resources data.

12 Capacity factor shown in Table 3-36 is based on all hours in January through March, 2010.

Figure 3-5 Average hourly day-ahead generation of wind units in PJM, January through March 2010 (See 2009 SOM, Figure 3-12)

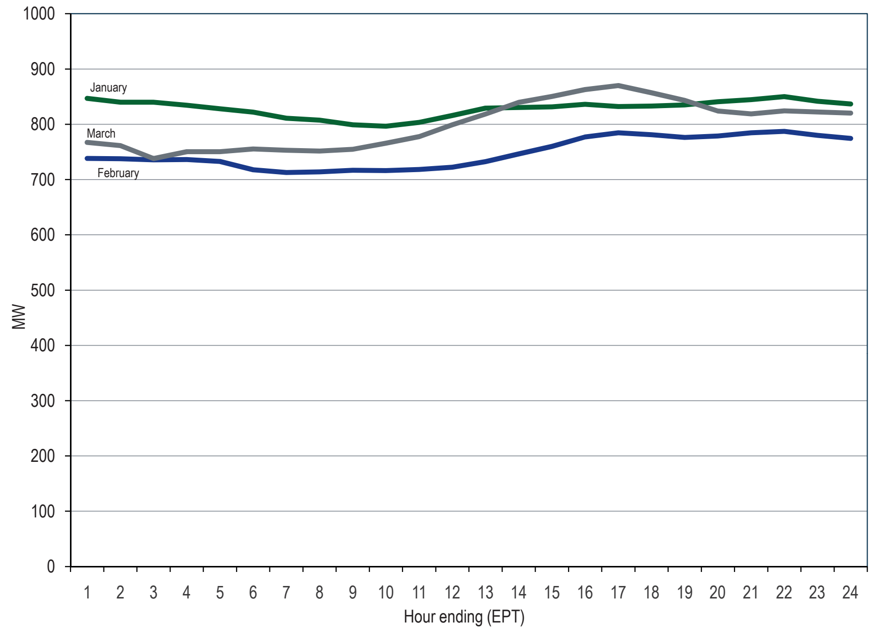
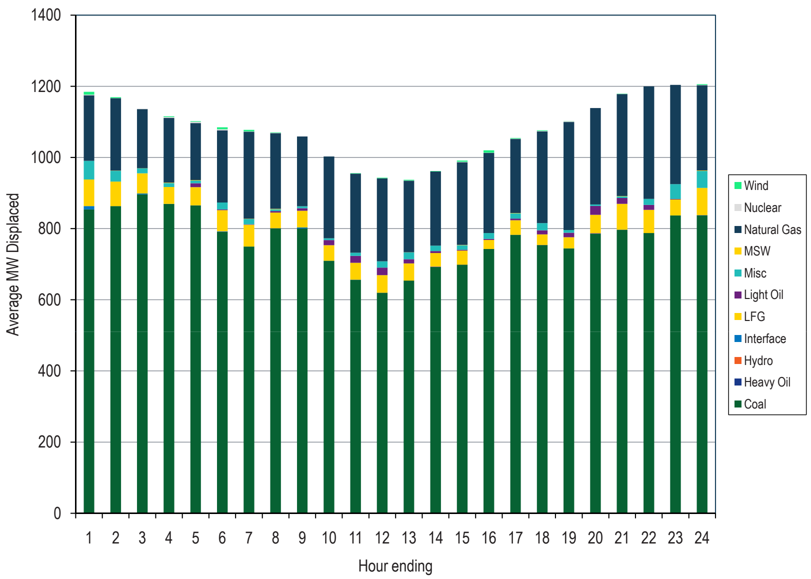


Figure 3-6 Marginal fuel at time of wind generation in PJM, January through March 2010 (See 2009 SOM, Figure 3-13)



Operating Reserve

Credit and Charge Categories

Table 3-38 Operating reserve credits and charges (See 2009 SOM, Table 3-50)

For Credits Received	By Charges Paid
Day ahead:	Day-ahead demand
Day-Ahead Energy Market →	Decrement bids
Day-ahead import transactions	Day-ahead export transactions
Synchronous condensing →	Real-time load
	Real-time export transactions
Balancing:	
Balancing energy market	Real-time deviations
Lost opportunity cost →	from day-ahead schedules
Real-time import transactions	
Balancing Energy Market Credits Received	**By Balancing Energy Market Charges Paid**
By (RTO, Eastern Region, Western Region)	Real-time load
Reliability Credits →	Real-time export transactions
Deviation Credits →	Real-time deviations
	from day-ahead schedules

Table 3-39 Operating reserve deviations (See 2009 SOM, Table 3-51)

Day ahead	Deviations	Real time
Day-ahead decrement bids	Demand (Withdrawal)	Real-time load
Day-ahead load	(RTO, East, West)	Real-time sales
Day-ahead sales		Real-time export transactions
Day-ahead export transactions		
Day-ahead increment offers	Supply (Injection)	Real-time purchases
Day-ahead purchases	(RTO, East, West)	Real-time import transactions
Day-ahead import transactions		
Day-ahead scheduled generation	Generator (Unit)	Real-time generation

Balancing Credits and Charges

Table 3-40 Balancing operating reserve allocation process (See 2009 SOM, Table 3-52)

	Reliability Credits	Deviation Credits
RTO	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV
East	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Credit and Charge Results

Overall Results

Table 3-41 Monthly operating reserve charges: Calendar year 2009 and January through March 2010 (See 2009 SOM, Table 3-54)

	2009 Charges				2010 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$9,260,150	$1,328,814	$30,116,725	$40,705,689	$10,281,351	$50,022	$40,308,020	$50,639,393
Feb	$7,434,068	$839,679	$16,548,988	$24,822,735	$11,425,494	$14,715	$22,365,749	$33,805,958
Mar	$9,549,963	$108,664	$26,025,562	$35,684,189	$8,836,886	$122,817	$16,160,276	$25,119,979
Apr	$6,998,364	$19,929	$13,251,273	$20,269,566				
May	$6,024,108	$5,543	$15,490,257	$21,519,908				
Jun	$6,722,329	$0	$19,339,846	$26,062,175				
Jul	$8,210,636	$38,643	$17,728,976	$25,978,255				
Aug	$7,697,174	$1	$21,164,586	$28,861,761				
Sep	$6,057,598	$13,611	$13,471,368	$19,542,577				
Oct	$7,046,301	$0	$17,026,425	$24,072,727				
Nov	$8,617,280	$22,639	$12,888,600	$21,528,519				
Dec	$11,323,263	$117,573	$25,353,409	$36,794,245				
Total	$94,941,235	$2,495,097	$228,406,015	$325,842,346	$30,543,731	$187,554	$78,834,045	$109,565,330
Share of Annual Charges	29.1%	0.8%	70.1%	100.0%	27.9%	0.2%	72.0%	100.0%

Table 3-42 Regional balancing charges allocation: January through March 2010[13] (See 2009 SOM, Table 3-55)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$10,176,719 16.1%	$383,645 0.6%	$10,560,364 16.7%	$21,710,093 34.3%	$13,665,395 21.6%	$6,456,026 10.2%	$41,831,514 66.1%	$52,391,878 82.8%
East	$278,704 0.4%	$11,446 0.0%	$290,150 0.5%	$1,802,666 2.8%	$1,400,649 2.2%	$392,516 0.6%	$3,595,832 5.7%	$3,885,982 6.1%
West	$4,925,038 7.8%	$157,162 0.2%	$5,082,200 8.0%	$1,023,136 1.6%	$533,414 0.8%	$391,554 0.6%	$1,948,105 3.1%	$7,030,305 11.1%
Total	$15,380,462 24.3%	$552,253 0.9%	$15,932,714 25.2%	$24,535,896 38.8%	$15,599,458 24.6%	$7,240,096 11.4%	$47,375,451 74.8%	$63,308,165 100%

13 The total charges shown in Table 3-42 do not equal the total balancing charges shown in Table 3-41 because the totals in Table 3-41 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-42 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while lost opportunity cost, cancellation, and local charges are allocated on an RTO basis, based on demand, supply, and generator deviations.

Deviations

Categories

Allocation

Table 3-43 Monthly balancing operating reserve deviations (MWh): Calendar year 2009 and January through March 2010 (See 2009 SOM, Table 3-56)

	2009 Deviations				2010 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	8,172,164	3,297,121	2,572,113	14,041,398	9,439,465	5,707,965	2,707,378	17,854,808
Feb	6,728,062	3,046,290	2,546,510	12,320,861	7,675,656	5,332,236	2,460,549	15,468,441
Mar	6,392,821	2,520,387	2,405,061	11,318,269	8,101,950	5,138,264	2,274,537	15,514,752
Apr	5,951,654	3,127,726	2,224,157	11,303,537				
May	6,624,696	3,787,650	2,699,616	13,111,962				
Jun	8,117,669	3,179,999	2,644,016	13,941,684				
Jul	9,237,956	3,914,230	2,213,828	15,366,014				
Aug	8,296,485	4,000,974	2,275,294	14,572,753				
Sep	7,360,536	3,691,646	2,577,095	13,629,277				
Oct	6,792,603	3,538,950	2,404,069	12,735,621				
Nov	6,561,634	3,586,432	2,267,083	12,415,148				
Dec	8,399,099	4,898,506	1,775,964	15,073,569				
Total	88,635,377	42,589,911	28,604,806	159,830,094	25,217,072	16,178,465	7,442,464	48,838,001
Share of Annual Deviations	55.5%	26.6%	17.9%	100.0%	51.6%	33.1%	15.2%	100.0%

Table 3-44 Regional charges determinants (MWh): January through March 2010 (See 2009 SOM, Table 3-57)

	Reliability Charge Determinants			Deviation Charge Determinants				
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total	Total
RTO	175,139,532	6,517,020	181,656,552	25,217,072	16,178,465	7,442,464	48,838,001	230,494,553
East	94,737,368	3,860,039	98,597,407	16,390,759	11,314,306	3,946,496	31,651,560	130,248,967
West	80,402,164	2,656,981	83,059,145	8,780,337	4,839,658	3,495,969	17,115,963	100,175,108

Balancing Operating Reserve Charge Rate

Figure 3-7 Daily RTO reliability and deviation rates ($/MWh): January through March 2010 (See 2009 SOM, Figure 3-14)

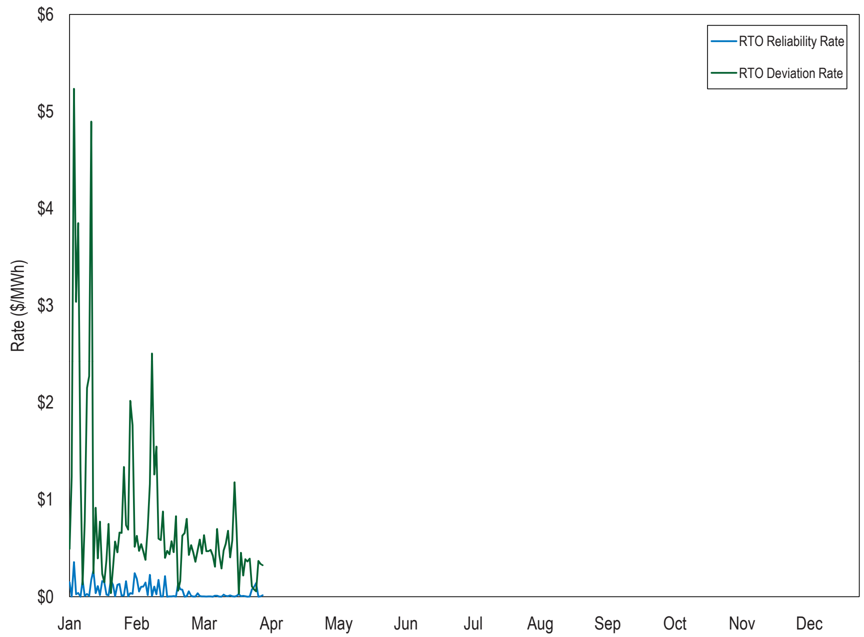


Figure 3-8 Daily regional reliability and deviation rates ($/MWh): January through March 2010 (See 2009 SOM, Figure 3-15)

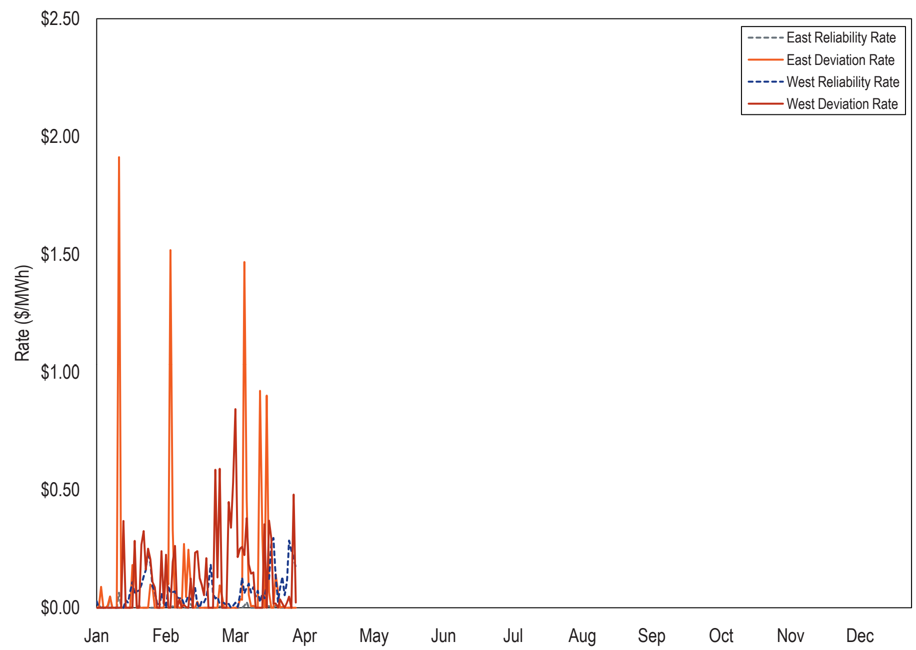


Table 3-45 Regional balancing operating reserve rates ($/MWh): January through March 2010 (See 2009 SOM, Table 3-58)

	Reliability	Deviations
RTO	0.056	0.792
East	0.003	0.111
West	0.066	0.123

Operating Reserve Credits by Category

Figure 3-9 Operating reserve credits: January through March 2010 (See 2009 SOM, Figure 3-16)

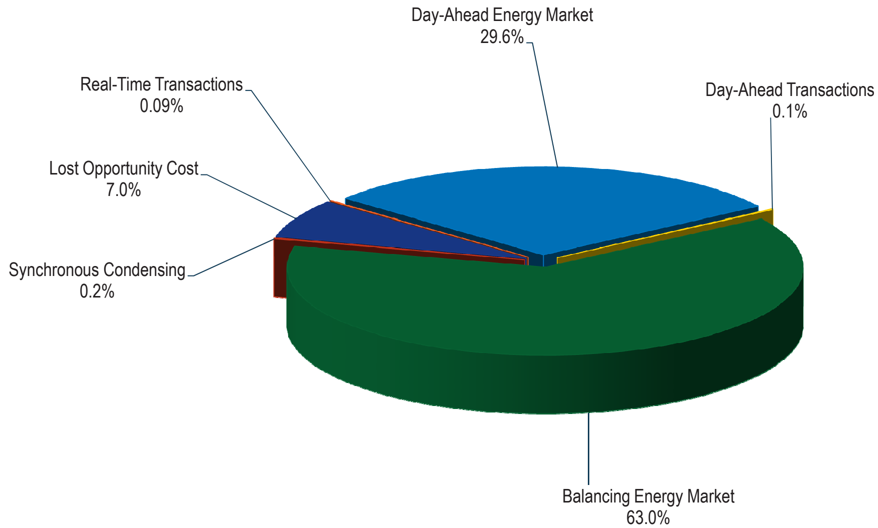


Table 3-46 Credits by month (By operating reserve market): January through March 2010 (See 2009 SOM, Table 3-59)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$10,199,534	$81,816	$50,022	$33,833,103	$0	$3,483,087	$47,647,563
Feb	$11,382,585	$42,910	$14,715	$17,640,757	$77,139	$1,868,879	$31,026,985
Mar	$8,831,771	$5,115	$122,817	$13,348,277	$15,603	$1,891,859	$24,215,441
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	$30,413,890	$129,841	$187,554	$64,822,137	$92,742	$7,243,826	$102,889,989
Share of Credits	29.6%	0.1%	0.2%	63.0%	0.1%	7.0%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-47 Credits by unit types (By operating reserve market): January through March 2010 (See 2009 SOM, Table 3-60)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	39.8%	0.0%	58.6%	1.6%	$51,800,402
Combustion Turbine	0.5%	1.2%	94.7%	3.7%	$16,242,447
Diesel	0.0%	0.0%	97.1%	2.9%	$36,916
Hydro	0.0%	0.0%	100.0%	0.0%	$3,539
Landfill	0.0%	0.0%	0.0%	100.0%	$4,440,478
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	32.6%	0.0%	63.9%	3.5%	$29,813,633
Wind Farm	0.0%	0.0%	2.8%	97.2%	$286,658

Table 3-48 Credits by operating reserve market (By unit type): January through March 2010 (See 2009 SOM, Table 3-61)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	67.8%	0.0%	46.8%	11.6%
Combustion Turbine	0.2%	100.0%	23.7%	8.3%
Diesel	0.0%	0.0%	0.1%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%
Landfill	0.0%	0.0%	0.0%	61.7%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	31.9%	0.0%	29.4%	14.6%
Wind Farm	0.0%	0.0%	0.0%	3.9%
Total	$30,413,890	$187,554	$64,822,137	$7,200,493

Geography of Balancing Credits and Charges

Table 3-49 Monthly balancing operating reserve charges and credits to generators (By location): January through March 2010 (See 2009 SOM, Table 3-65)

	Eastern Region						Western Region							
	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Total Unit Deviation Charges Percent of Total Operating Reserve Charges	Total Unit Credits Percent of Total Operating Reserve Credits
Jan	$1,909,329	$261,994	$2,171,324	$29,019,219	$2,741,214	$31,760,432	$1,952,189	$273,280	$2,225,469	$4,813,885	$741,874	$5,555,758	8.7%	78.3%
Feb	$1,071,403	$151,355	$1,222,758	$14,105,775	$1,393,404	$15,499,179	$999,618	$145,424	$1,145,042	$3,534,982	$475,475	$4,010,457	7.0%	62.9%
Mar	$565,725	$120,609	$686,334	$7,861,107	$1,399,277	$9,260,384	$741,832	$160,071	$901,904	$5,487,170	$492,582	$5,979,752	6.3%	62.9%
Apr														
May														
Jun														
Jul														
Aug														
Sep														
Oct														
Nov														
Dec														
Average	49.0%	48.0%	48.9%	78.7%	76.4%	78.4%	51.0%	52.0%	51.1%	21.3%	23.6%	21.6%	7.3%	68.0%

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

Table 3-50 Regional balancing operating reserve credits: January through March 2010 (See 2009 SOM, Table 3-66)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$10,270,330	$41,572,827	$51,843,157
East	$290,150	$3,595,832	$3,885,982
West	$5,082,200	$1,948,105	$7,030,305
Total	$15,642,681	$47,116,763	$62,759,444

Table 3-51 Total deviations: January through March 2010 (See 2009 SOM, Table 3-67)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	24,910,065	16,031,262	7,371,964	48,313,290

Table 3-52 Charge allocation under old operating reserve construct: January through March 2010 (See 2009 SOM, Table 3-68)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	24,910,065	16,031,262	7,371,964	48,313,290
Balancing Rate ($/MWh)	1.299	1.299	1.299	1.299
Charges ($)	$32,358,421	$20,824,768	$9,576,255	$62,759,444

Table 3-53 Actual regional credits, charges, rates and charge allocation (MWh): January through March 2010 (See 2009 SOM, Table 3-69)

	Reliability Charges				Deviation Charges				
	Reliability Credits ($)	RT Load and Exports (MWh)	Reliability Rate ($/MWh)	Reliability Charges ($)	Deviation Credits ($)	Deviations (MWh)	Deviation Rate ($/MWh)	Deviation Charges ($)	Total Charges ($)
RTO	$10,270,330	179,728,903	0.057	$10,270,330	$41,572,827	48,313,290	0.860	$41,572,827	$51,843,157
East	$290,150	98,597,407	0.003	$290,150	$3,595,832	31,651,560	0.114	$3,595,832	$3,885,982
West	$5,082,200	83,059,145	0.061	$5,082,200	$1,948,105	17,115,963	0.114	$1,948,105	$7,030,305
Total	$15,642,681	179,728,903	NA	$15,642,681	$47,116,763	48,313,290	NA	$47,116,763	$62,759,444

Table 3-54 Difference in total charges between old rules and new rules: January through March 2010 (See 2009 SOM, Table 3-70)

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Charges (Old)	$0	$0	$0	$32,358,421	$20,824,768	$9,576,255	$62,759,444
Charges (Current)	$15,100,080	$542,601	$15,642,681	$24,384,538	$15,526,886	$7,205,339	$47,116,763
Difference	$15,100,080	$542,601	$15,642,681	($7,973,883)	($5,297,882)	($2,370,915)	($15,642,681)

Impact on decrement bids and incremental offers

Table 3-55 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): January through March 2010 (see 2009 SOM, Table 3-71)

Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)
Jan	8,291,432	13,029,516	2,463,852	3,452,047
Feb	8,323,844	11,828,780	2,004,162	2,234,045
Mar	8,032,429	11,159,303	2,150,898	2,594,826
Apr				
May				
Jun				
Jul				
Aug				
Sep				
Oct				
Nov				
Dec				
Total	24,647,705	36,017,600	6,618,912	8,280,918

Table 3-56 Comparison of balancing operating reserve charges to virtual bids: January through March 2010 (See 2009 SOM, Table 3-72)

Month	Charges Under Current Rules	Charges Under Old Rules	Difference
Jan	$10,131,402	$12,596,576	($2,465,174)
Feb	$3,939,289	$5,368,599	($1,429,310)
Mar	$3,280,123	$4,405,853	($1,125,730)
Total	$17,350,813	$22,371,028	($5,020,215)

Table 3-57 Summary of impact on virtual bids under balancing operating reserve allocation: January through March 2010 (See 2009 SOM, Table 3-73)

Region	Adjusted Increment Offer Deviations	Adjusted Decrement Bid Deviations	Total Adjusted Virtual Deviations	Balancing Rate Under Current Rules	Balancing Rate Under Old Rules	Charges Under Current Rules	Charges Under Old Rules	Differerence
RTO	6,618,912	8,280,918	14,899,830	0.94	1.38	$15,650,032	$22,371,028	($6,720,997)
East	4,481,203	4,848,963	9,330,165	0.12	0.00	$1,097,057	$0	$1,097,057
West	2,113,208	3,385,979	5,499,187	0.12	0.00	$603,725	$0	$603,725

Segmented Make Whole Payments

Table 3-58 Impact of segmented make whole payments: December 2008 through March 2010 (See 2009 SOM, Table 3-74)

Year	Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
2008	Dec	$17,879,706	$18,564,627	$684,920
2009	Jan	$24,958,891	$26,413,119	$1,454,228
2009	Feb	$13,834,755	$14,391,550	$556,795
2009	Mar	$21,434,893	$22,200,141	$765,248
2009	Apr	$10,532,594	$10,741,260	$208,666
2009	May	$13,499,668	$13,813,209	$313,541
2009	Jun	$15,111,383	$16,058,545	$947,162
2009	Jul	$14,657,498	$15,414,023	$756,525
2009	Aug	$14,467,711	$15,602,754	$1,135,043
2009	Sep	$10,293,949	$10,576,618	$282,669
2009	Oct	$14,337,978	$14,605,878	$267,900
2009	Nov	$8,889,163	$9,091,845	$202,682
2009	Dec	$19,403,859	$20,002,885	$599,026
2010	Jan	$32,822,043	$33,772,219	$950,176
2010	Feb	$17,343,775	$17,631,590	$287,815
2010	Mar	$13,143,537	$13,357,509	$213,972
Total		$249,467,865	$258,880,263	$9,412,397

Table 3-59 Impact of segmented make whole payments (By unit type): January through March 2010 (See 2009 SOM, Table 3-75)

Unit Type	Number of Unit-Days	Average Daily Balancing Credits (Old Rules)	Average Daily Balancing Credits (New Rules)	Average Daily Difference	Total Balancing Credits (Old Rules)	Total Balancing Credits (New Rules)	Total Difference
Combined-Cycle	242	$4,685	$8,177	$3,492	$1,133,762	$1,978,773	$845,011
Medium Frame Combustion Turbine (30 - 65 MW)	434	$2,255	$2,802	$547	$978,722	$1,215,955	$237,233
Large Frame Combustion Turbine (135 - 180 MW)	24	$17,622	$24,943	$7,321	$422,925	$598,631	$175,705
Petroleum/Gas Steam (Post-1985)	13	$5,227	$11,677	$6,450	$67,946	$151,798	$83,852
Sub-Critical Coal	98	$51	$618	$567	$5,023	$60,591	$55,569
Medium-Large Frame Combustion Turbine (65 - 125 MW)	60	$3,960	$4,745	$786	$237,571	$284,716	$47,145
Small Frame Combustion Turbine (0 - 29 MW)	34	$3,177	$3,361	$183	$108,025	$114,264	$6,239
Diesel	1	$0	$1,210	$1,210	$0	$1,210	$1,210

Table 3-60 Share of balancing operating reserve increases for segmented make whole payments (By unit type): January through March 2010 (See 2009 SOM, Table 3-76)

Unit Type	Share of Increase
Combined-Cycle	58.2%
Steam	9.6%
Combustion Turbines	32.1%
Diesel	0.1%

Unit Operating Parameters

Table 3-61 Unit Parameter Limited Schedule Matrix (See 2009 SOM, Table 3-77)

Unit Type	Minimum Run Time (Hours)	Minimum Down Time (Hours)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio
Petroleum/Gas Steam (Pre-1985)	8 or Less	7 or Less	1 or More	7 or More	3 or More
Petroleum/Gas Steam (Post-1985)	5.5 or Less	3.5 or Less	2 or More	11 or More	2 or More
Combined-Cycle	6 or Less	4 or Less	2 or More	11 or More	1.5 or More
Sub-Critical Coal	15 or Less	9 or Less	1 or More	5 or More	2 or More
Super-Critical Coal	24 or Less	84.0	1 or More	2 or More	1.5 or More
Small Frame and Aero Combustion Turbine (0 - 29 MW)	2 or Less	2 or Less	2 or More	14 or More	1 or More
Medium Frame and Aero Combustion Turbine (30 - 125 MW)	3 or Less	2 or Less	2 or More	14 or More	1 or More
Medium-Large Frame Combustion Turbine (65 - 125 MW)	5 or Less	3 or Less	2 or More	14 or More	1 or More
Large Frame Combustion Turbine (135 - 180 MW)	5 or Less	4 or Less	2 or More	14 or More	1 or More

Table 3-62 Units receiving credits from a parameter limited schedule: January through March 2010 (See 2009 SOM, Table 3-78)

Unit Type	Number of Units	Observations
Combined-Cycle	1	1
Large Frame Combustion Turbine (135 - 180 MW)	2	3
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	33
Petroleum/Gas Steam (Pre-1985)	1	2
Sub-Critical Coal	13	76

Concentration of Unit Ownership for Operating Reserve Credits

Concentration of Operating Reserve Credits

Table 3-63 Unit operating reserve credits for units (By zone): January through March 2010 (See 2009 SOM, Table 3-80)

Zone	Day Ahead Generator Credit	Synchronous Condensing Credit	Balancing Generator Credit	Lost Opportunity Cost Credit	Total Operating Reserve Credits	Percent of Total Operating Reserve Credits
AECO	$42,135	$3,971	$273,305	$0	$319,411	0.3%
AEP	$995,581	$8,047	$9,045,216	$410,759	$10,459,603	10.2%
AP	$431,867	$0	$971,017	$741,671	$2,144,555	2.1%
BGE	$1,105,035	$0	$1,378,204	$0	$2,483,240	2.4%
ComEd	$324,867	$0	$771,834	$533,951	$1,630,651	1.6%
DAY	$103,889	$0	$372,322	$9,670	$485,882	0.5%
Dominion	$548,253	$0	$5,092,436	$3,967,594	$9,608,283	9.4%
DPL	$1,120,432	$2,505	$2,429,764	$246,752	$3,799,454	3.7%
DLCO	$1,035,242	$0	$2,598,493	$2,114	$3,635,849	3.5%
JCPL	$1,981,371	$0	$2,282,765	$0	$4,264,136	4.2%
Met-Ed	$90,015	$0	$189,033	$0	$279,048	0.3%
PECO	$1,248,977	$2,095	$932,631	$77,206	$2,260,910	2.2%
PENELEC	$998	$8,905	$137,554	$158,869	$306,326	0.3%
Pepco	$1,292,229	$0	$5,228,386	$815,330	$7,335,946	7.2%
PPL	$77,060	$0	$3,448,549	$234,167	$3,759,776	3.7%
PSEG	$20,010,456	$156,309	$29,575,434	$33,977	$49,776,175	48.5%
External	$0	$0	$0	$0	$0	0.0%
Total	$30,408,409	$181,832	$64,726,942	$7,232,060	$102,549,243	100.0%

Table 3-64 Top 10 units and organizations receiving total operating reserve credits: January through March 2010 (See 2009 SOM, Table 3-81)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$18,619,098	18.1%	18.1%	$49,165,106	47.9%	47.9%
2	$15,086,428	14.7%	32.8%	$8,141,922	7.9%	55.8%
3	$5,101,609	5.0%	37.8%	$6,291,698	6.1%	61.9%
4	$3,172,914	3.1%	40.9%	$5,679,306	5.5%	67.5%
5	$2,300,662	2.2%	43.1%	$4,714,947	4.6%	72.1%
6	$1,842,375	1.8%	44.9%	$3,933,095	3.8%	75.9%
7	$1,668,308	1.6%	46.5%	$3,172,914	3.1%	79.0%
8	$1,452,456	1.4%	48.0%	$3,020,195	2.9%	81.9%
9	$1,225,256	1.2%	49.2%	$2,263,372	2.2%	84.1%
10	$1,198,615	1.2%	50.3%	$1,381,434	1.3%	85.5%

Table 3-65 Top 10 units and organizations receiving day-ahead generator credits: January through March 2010 (See 2009 SOM, Table 3-82)

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$9,030,534	29.7%	29.7%	$19,975,372	65.7%	65.7%
2	$4,481,756	14.7%	44.4%	$1,840,078	6.1%	71.7%
3	$3,300,358	10.9%	55.3%	$1,125,078	3.7%	75.4%
4	$1,840,078	6.1%	61.3%	$1,088,419	3.6%	79.0%
5	$1,593,833	5.2%	66.6%	$970,016	3.2%	82.2%
6	$1,086,840	3.6%	70.1%	$872,676	2.9%	85.1%
7	$963,905	3.2%	73.3%	$751,554	2.5%	87.5%
8	$585,511	1.9%	75.2%	$654,220	2.2%	89.7%
9	$348,635	1.1%	76.4%	$573,047	1.9%	91.6%
10	$323,106	1.1%	77.4%	$522,597	1.7%	93.3%

Table 3-66 Top 10 units and organizations receiving synchronous condensing credits: January through March 2010 (See 2009 SOM, Table 3-83)

	Units			Organizations		
Rank	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution
1	$20,686	11.0%	11.0%	$156,309	83.3%	83.3%
2	$14,462	7.7%	18.7%	$13,768	7.3%	90.7%
3	$12,753	6.8%	25.5%	$8,905	4.7%	95.4%
4	$11,874	6.3%	31.9%	$6,477	3.5%	98.9%
5	$10,763	5.7%	37.6%	$2,095	1.1%	100.0%
6	$10,748	5.7%	43.3%			
7	$8,118	4.3%	47.7%			
8	$7,821	4.2%	51.8%			
9	$7,264	3.9%	55.7%			
10	$7,182	3.8%	59.5%			

Table 3-67 Top 10 units and organizations receiving balancing generator credits: January through March 2010 (See 2009 SOM, Table 3-84)

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$14,137,342	21.8%	21.8%	$28,999,449	44.7%	44.7%
2	$6,055,299	9.3%	31.2%	$7,136,836	11.0%	55.7%
3	$1,801,251	2.8%	33.9%	$5,328,108	8.2%	64.0%
4	$1,598,443	2.5%	36.4%	$5,217,078	8.0%	72.0%
5	$1,441,118	2.2%	38.6%	$2,827,369	4.4%	76.4%
6	$1,332,836	2.1%	40.7%	$1,982,601	3.1%	79.4%
7	$1,198,615	1.8%	42.5%	$1,845,025	2.8%	82.3%
8	$1,181,333	1.8%	44.3%	$1,332,836	2.1%	84.3%
9	$930,953	1.4%	45.8%	$1,171,163	1.8%	86.1%
10	$904,293	1.4%	47.2%	$1,158,356	1.8%	87.9%

Table 3-68 Top 10 units and organizations receiving lost opportunity cost credits: January through March 2010 (See 2009 SOM, Table 3-85)

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$886,383	12.2%	12.2%	$4,713,550	65.1%	65.1%
2	$682,772	9.4%	21.7%	$762,534	10.5%	75.6%
3	$635,812	8.8%	30.4%	$391,996	5.4%	81.0%
4	$591,740	8.2%	38.6%	$390,543	5.4%	86.4%
5	$544,001	7.5%	46.1%	$208,377	2.9%	89.3%
6	$522,921	7.2%	53.3%	$132,410	1.8%	91.1%
7	$427,283	5.9%	59.2%	$70,289	1.0%	92.1%
8	$335,251	4.6%	63.9%	$65,973	0.9%	93.0%
9	$241,343	3.3%	67.2%	$61,475	0.8%	93.8%
10	$216,586	3.0%	70.2%	$57,968	0.8%	94.6%

January 3, 2010

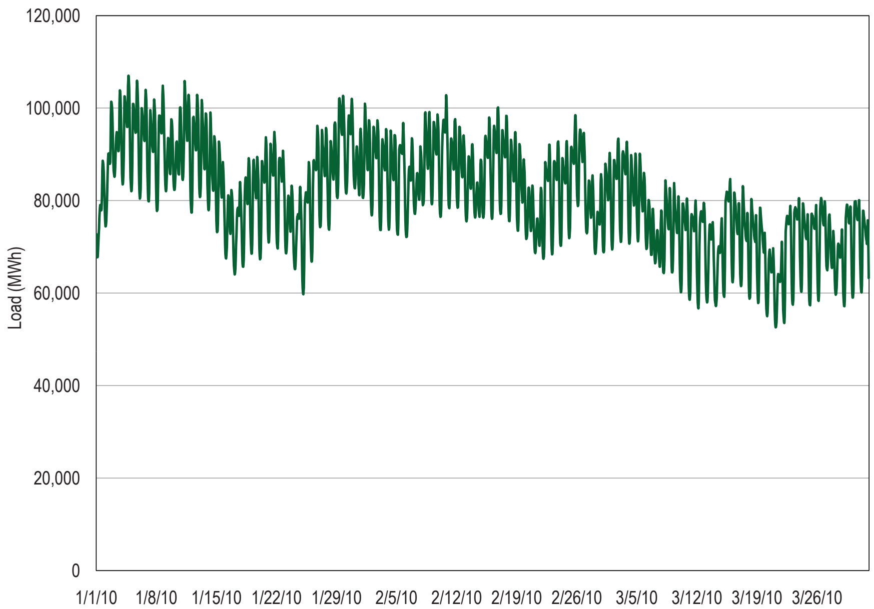
A Spike in Operating Reserves Charges

The spike in the RTO Balancing Deviation Rate that occurred on Sunday, January 3, 2010, was largely the result of $3,873,457 paid to generators in RTO Deviation Credits, which accounted for 81.6 percent of the balancing operating reserve credits for that day. The RTO Deviation rate on January 3 was 5.2333 $/MWh (or $3,873,457 divided by 740,159 MWh). See Table 3-69. The deviation rate was 4.88 standard deviations higher than the average RTO Deviation Rate of 0.7924 $/MWh for the period of January 1, 2010 through March 31, 2010.

The high level of balancing operating reserve credits can be attributed to multiple high voltage and interface constraints which limited power transfers from west to the east. As a result, multiple natural gas fired combined-cycles and combustion turbines in the eastern region were turned on during off-peak hours and were made whole to their minimum run times, or kept on for reliability or to compensate for other units not following day ahead schedules or not following dispatch.

January 3, 2010 was a relatively high PJM load day for the first quarter of the year. At HE 19, the PJM load reached 106,383 MW, which is in the top 0.5 percent of hourly loads for the first quarter of 2010. Figure 3-10 shows the hourly PJM load for the first three months of 2010.

Figure 3-10 Figure 4 Hourly PJM Load: January 1, 2010 through March 31, 2010 (New Figure)



There was significant price separation among the 5-minute real-time zonal LMPs throughout the day on January 3. The highest levels of price separation occurred during the morning off-peak hours. Figure 3-11 shows the five minute zonal LMPs. Figure 3-12 shows the hourly zonal and PJM loads.

Figure 3-11 Five Minute Zonal LMPs: January 3, 2010 (New Figure)

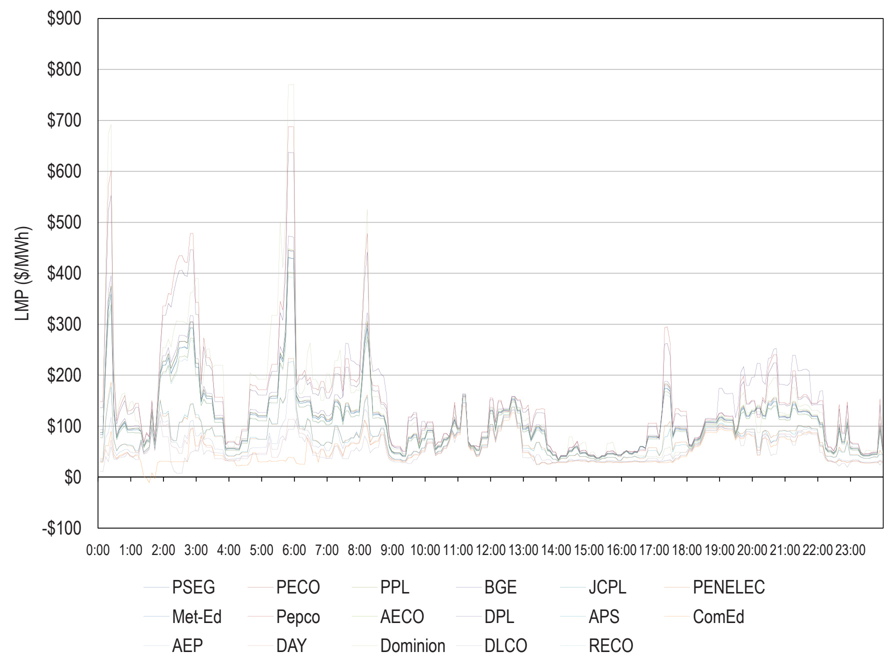


Figure 3-12 Hourly Zonal Loads: January 3, 2010 (New Figure)

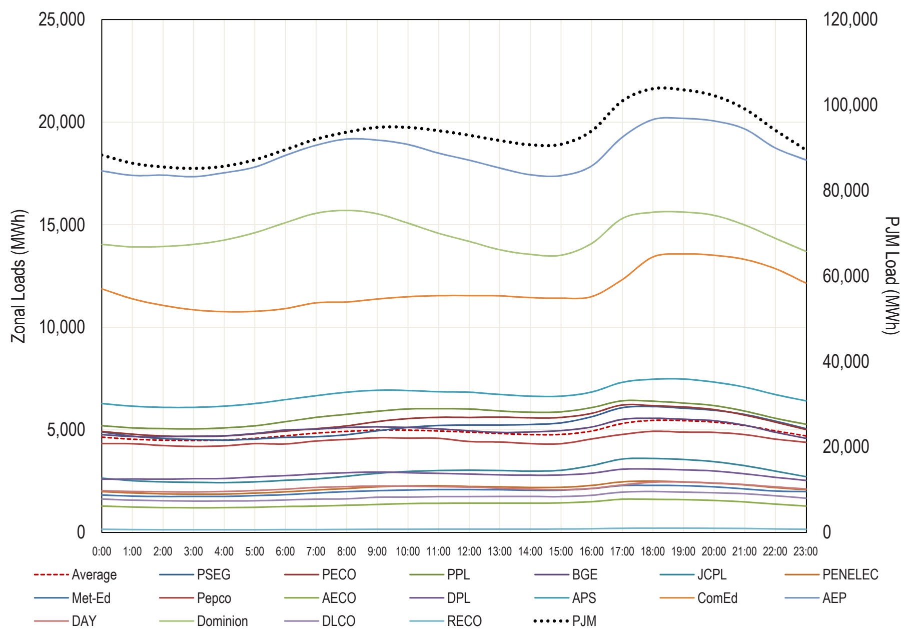


Figure 3-13 shows the real-time constraints on the PJM system and relative shadow prices for January 3, 2010. The constraints that contributed to RTO credits (units called on for transmission constraints 500kV and above) were the 5004/5005 interface, the AEP—DOM interface, the AP South interface, the Bedington—Black Oak interface, Cloverdale—Lexington, Harrison—Pruntytown, Mt. Storm—Pruntytown, and Line 500kV 539 (Bristers—Ox). The credits associated with all other constraints would be allocated to either Eastern or Western credits.

Figure 3-13 Figure 7 Real-time constraints and shadow prices: January 3, 2010 (New Figure)

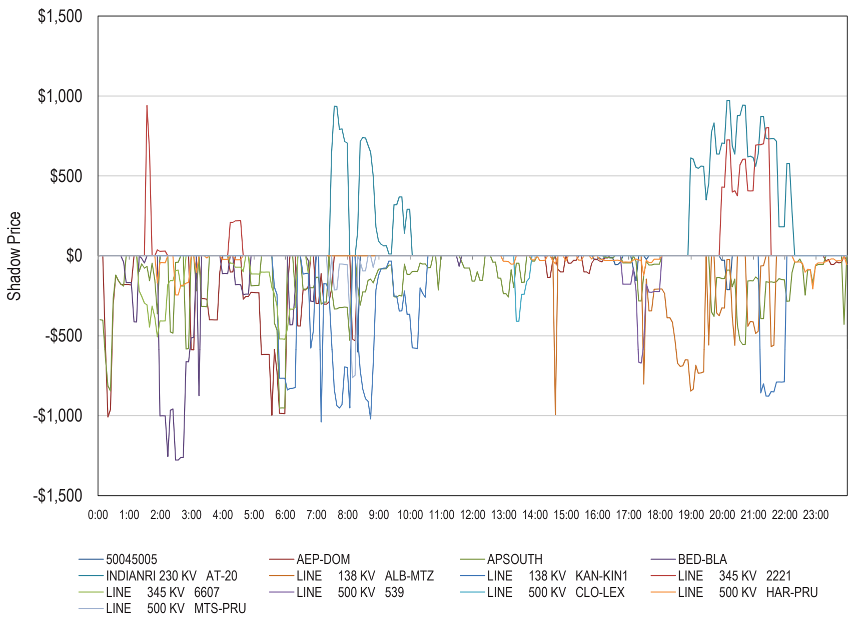


Table 3-69 shows RTO, East, and West charges, credits, and MWh for January 3. RTO deviation credits accounted for $3,873,457, or 81.6 percent, of the total credits for the day of $4,746,701. Charges paid by demand deviations were 46.4 percent of the total charges for the day, while charges paid by supply deviations were 21.2 percent and generator deviations 14.0 percent.

Table 3-69 Regional Credits, Charges, and Deviations Breakdown: January 3, 2010 (New Table)

	Reliability			Deviations				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO (MWh)	2,230,391	64,695	2,295,086	420,621	192,274	127,264	740,159	3,035,244
RTO (Charges / Credits)	$794,170	$23,036	$817,205	$2,201,228	$1,006,222	$666,006	$3,873,457	$4,690,662
RTO (% of Total Charges)	16.7%	0.5%	17.2%	46.4%	21.2%	14.0%	81.6%	98.8%
East (MWh)	1,245,523	46,585	1,292,108	276,559	110,748	85,088	472,394	1,764,503
East (Charges / Credits)	$13,581	$508	$14,089	$24,559	$9,835	$7,556	$41,950	$56,039
East (% of Total Charges)	0.3%	0.0%	0.3%	0.5%	0.2%	0.2%	0.9%	1.2%
West (MWh)	984,867	18,110	1,002,977	143,503	81,506	42,724	267,733	1,270,710
West (Charges / Credits)	$0	$0	$0	$0	$0	$0	$0	$0
West (% of Total Charges)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sum of Charges	$807,751	$23,544	$831,294	$2,225,788	$1,016,057	$673,562	$3,915,407	$4,746,701

Table 3-70 shows that 88.0 percent of credits paid to combined cycles were in the form of balancing generator credits, 95.2 percent of credits earned by combustion turbines were balancing generator credits, and 74.6 percent of credits earned by steam units were balancing generator credits.

Table 3-70 Credits by unit types (By operating reserve market): January 3, 2010 (New Table)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	11.9%	0.0%	88.0%	0.1%	$2,194,558
Combustion Turbine	0.0%	0.7%	95.2%	4.1%	$2,357,343
Diesel	0.0%	0.0%	100.0%	0.0%	$1,350
Hydro	0.0%	0.0%	0.0%	0.0%	$0
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	5.7%	0.0%	74.6%	19.7%	$462,624
Wind Farm	0.0%	0.0%	0.0%	0.0%	$0

The data shown in Table 3-71 shows that 49.6 percent of the balancing generator credits were paid to combustion turbines, 42.7 to combined-cycles, and 7.6 percent to steam units.

Table 3-71 Credits by operating reserve market (By unit type): January 3, 2010 (New Table)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	90.8%	0.0%	42.7%	1.1%
Combustion Turbine	0.0%	100.0%	49.6%	50.7%
Diesel	0.0%	0.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%
Steam	9.2%	0.0%	7.6%	48.1%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$288,090	$16,466	$4,522,371	$188,946

Table 3-72 shows the top 10 units in each category that received operating reserve credits. The top 10 units receiving balancing generator credits received 52.7 percent of the total balancing generator credits, or $2,578,795.

Table 3-72 Top 10 units receiving operating reserve credits: January 3, 2010 (New Table)

Unit Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$178,592	62.0%	62.0%	$2,318	14.1%	14.1%	$445,291	9.1%	9.1%
2	$73,680	25.6%	87.6%	$2,149	13.0%	27.1%	$421,415	8.6%	17.7%
3	$16,147	5.6%	93.2%	$2,149	13.0%	40.2%	$401,681	8.2%	25.9%
4	$9,200	3.2%	96.4%	$2,052	12.5%	52.6%	$292,022	6.0%	31.9%
5	$8,818	3.1%	99.4%	$1,920	11.7%	64.3%	$178,228	3.6%	35.5%
6	$1,566	0.5%	100.0%	$900	5.5%	69.8%	$171,209	3.5%	39.0%
7	$88	0.0%	100.0%	$900	5.5%	75.2%	$168,277	3.4%	42.5%
8	$0	0.0%	100.0%	$887	5.4%	80.6%	$167,576	3.4%	45.9%
9	$0	0.0%	100.0%	$887	5.4%	86.0%	$167,433	3.4%	49.3%
10	$0	0.0%	100.0%	$887	5.4%	91.4%	$165,664	3.4%	52.7%

Unit Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$62,651	20.7%	20.7%	$445,291	8.0%	8.0%
2	$38,910	12.9%	33.6%	$421,415	7.6%	15.6%
3	$32,501	10.7%	44.3%	$401,681	7.2%	22.9%
4	$22,577	7.5%	51.8%	$292,022	5.3%	28.2%
5	$18,092	6.0%	57.7%	$218,680	3.9%	32.1%
6	$17,833	5.9%	63.6%	$178,228	3.2%	35.3%
7	$17,149	5.7%	69.3%	$171,209	3.1%	38.4%
8	$15,326	5.1%	74.4%	$168,277	3.0%	41.4%
9	$11,519	3.8%	78.2%	$167,576	3.0%	44.5%
10	$8,687	2.9%	81.1%	$167,433	3.0%	47.5%

SECTION 4 – INTERCHANGE TRANSACTIONS

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials. The external regions include both market and non market balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Market.** During the first three months of 2010, PJM was a net exporter of energy in the Real-Time Market in all months. The Real-Time monthly net interchange averaged -281 GWh.[1] Gross monthly import volumes averaged 3,837 GWh while gross monthly exports averaged 4,118 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market.** During the first three months of 2010, PJM was a net exporter of energy in the Day-Ahead Market in all months. The Day-Ahead monthly net interchange averaged -260 GWh. Gross monthly import volumes averaged 5,182 GWh while gross monthly exports averaged 5,442 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Market versus the Real-Time Market.** During the first three months of 2010, gross imports in the Day-Ahead Energy Market were 135 percent of the Real-Time Market's gross imports (111 percent for the calendar year 2009), gross exports in the Day-Ahead Market were 132 percent of the Real-Time Market's gross exports (127 percent for the calendar year 2009) and net interchange in the Day-Ahead Energy Market was 93 percent of net interchange in the Real-Time Energy Market (-842 GWh in the Real-Time Market and -781 GWh in the Day-Ahead Market).

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market, during the first three months of 2010, there were net exports at 11 of PJM's 21 interfaces. The top three net exporting interfaces in the Real-Time Market accounted for 73 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 28 percent, PJM/Neptune (NEPT) with 23 percent and PJM/MidAmerican Energy Company (MEC) with 22 percent of the net export volume. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 57 percent of the total net PJM exports in the Real-Time Market. Eight PJM interfaces had net imports, with two importing interfaces accounting for 78 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 61 percent and PJM/Michigan Electric Coordinated System (MECS) with 17 percent.[2]

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, there were net exports at 12 of PJM's 21 interfaces. The top four net exporting interfaces accounted for 84 percent of the total net exports: PJM/MEC with 36 percent, PJM/western Alliant Energy Corporation (ALTW) with 20 percent, PJM/Neptune (NEPT) with 15 percent and PJM/NYIS with 13 percent. Eight PJM interfaces had net imports in the Day-Ahead Market, with two interfaces accounting for 89 percent of the total net imports: PJM/OVEC with 58 percent and PJM/Michigan Electric Coordinated System (MECS) with 31 percent.[3]

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** During the first three months of 2010, the relationship between prices at the PJM/MISO Interface and at the MISO/PJM Interface reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO. Over the first three months of 2010, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $34.82 while the Midwest ISO LMP at the border was $35.20, a difference of $0.38. While the average hourly flow reflected imports into PJM from the Midwest ISO, further analysis of hourly interchange shows patterns of expected market participant response that created price convergence at the PJM/MISO Interface.

1 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

2 In the Real-Time Market, two PJM interfaces had a net interchange of zero.

3 In the Day-Ahead Market, one PJM interface had a net interchange of zero.

- **PJM and New York ISO Interface Prices.** During the first three months of 2010, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus reflected economic fundamentals, as did the relationship between interface price differentials and power flows between PJM and the NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and the NYISO. Over the first three months of 2010, the PJM average hourly LMP at the PJM/NYISO border was $45.86 while the NYISO LMP at the border was $44.06, a difference of $1.80. While the average hourly flow reflected exports from PJM into the NYISO, further analysis of hourly interchange shows patterns of expected market participant response that created price convergence at the PJM/NYISO Interface.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[4] On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering.

  The PJM/NYISO JOA does not include provisions for market based congestion management or other market to market activity, and, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued during the first three months of 2010. By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order."[5] After working in collaboration with PJM, the Midwest ISO and the Ontario Independent Electricity System Operator (IESO), including an opportunity to comment by stakeholders and market monitors, the NYISO filed on January 12, 2010, a *Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.*[6]

- **PJM and Midwest ISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during the first three months of 2010. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates, allow for redispatch of the PJM and MISO regions as though they were one large control area. The MMU believes that this approach should constitute the prevailing industry standard. This conceptual achievement, however, has not been matched by adequate attention to the details of its administration.

  The market based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[7] In 2009, the Midwest ISO requested that PJM review the components of the CMP to verify data accuracy. During this review, it was found that some data inputs to the market flow calculator were incorrect during the time period from April 2005 through June 2009. The resulting inaccuracies in the market flow calculation meant that the Midwest ISO received less compensation than appropriate. While the errors in input data have been corrected for market to market activity moving forward, the Midwest ISO and PJM are currently in the process of calculating the shortfall. PJM reported an estimate of 77.5 million dollars.[8] On March 8, 2010, after the settlement discussions mediated by the Federal Energy Regulatory Commission (FERC) ended, the Midwest ISO filed complaints with FERC against PJM.[9] The complaints claim that, "By failing to accurately reflect market flows, PJM has caused Midwest ISO participants to be underpaid for congestion relief in the amount of $130 million dollars between 2005 and 2009," and that, "PJM has demanded repayment of sums related to mutually agreed use of proxy flowgates, in violation of the JOA, and has failed without explanation to initiate the market to market process when the binding constraint is an RCF under PJM control … [such that] PJM charges its stakeholders unnecessary costs for congestion, increases PJM generator revenues, and deprives the Midwest ISO generators of revenue."[10] On April 12, 2010, PJM answered and filed a counter complaint, contending that, "Midwest ISO violated the JOA by improperly initiating the market-to-market process under the JOA using

4 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed April 22, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

5 128 FERC ¶61,049 (Ordering Para. B), order on clarification, 128 FERC ¶61,239.

6 See NYISO. "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" Docket No. ER08-1281-004 (January 12, 2010) (Accessed April 22, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf> (131 KB).

7 See PJM. "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) (Accessed April 22, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,294 KB).

8 See PJM. "PJM/MISO Market Flow Calculation Error"(September 10, 2009) (Accessed April 22, 2010) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).

9 Complaints of the Midwest Independent Transmission System Operator, Inc., filed Dockets Nos. EL10-45-000 & EL10-46-000 (respectively, MISO Complaint I and MISO Complaint II).

10 MISO Complaint I at 33; MISO Complaint II at 12.

substitute or proxy flowgates."[11] These matters are now pending before the Commission. The Market Monitor is concerned that this imbroglio over administration of the JOA will unduly detract from its ability to serve as the basis for moving forward industry practice for managing congestion and loop flows at system interfaces.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[12] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through the first three months of 2010.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[13] On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through the first three months of 2010. As part of this agreement, both parties agreed to develop a formal CMP. On February 2, 2010, PJM and PEC filed a revision to the JOA to include a Congestion Management Protocol.[14] The MMU responded to the filing on February 23, 2010.[15] The MMU response noted that the agreement included discriminatory treatment for the identified transactions with respect to access to ATC, that a regional approach is preferable to entering into agreements with individual neighbors, and that a sunset should be required in order to ensure that the next step towards such regional coordination is taken without delay. PJM and PEC filed an answer on March 10, 2010, to which the MMU responded on April 2, 2010. PJM and PEC filed an additional answer on April 19, 2010. [16] The matter currently is pending before the Commission.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[17] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region within the NERC Southeastern Electric Reliability Council (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

Other Agreements with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During the first three months of 2010, PJM continued to operate under the terms of the operating protocol developed in 2005.[18] On February 23, 2009, PJM filed a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed roll-over of the agreements under the PJM OATT.[19] After NRG and FERC trial staff contested the settlement, the Commission found that the record does not sufficiently address "threshold issues" concerning the roll-over of these contracts, including the impact on locational marginal pricing, and whether this result would be unduly discriminatory.[20] The Commission has required the parties to brief these issues and has reserved the right to establish additional procedures if these briefs raise material issues of disputed fact.[21]

  The MMU has reviewed the briefs filed in this proceeding on April 21, 2010, and believes that they raise questions about whether allowing roll over is appropriate.[22] There is reason for concern that continuing these agreements may interfere with the efficient management of the NYISO/PJM seam, accord preferential access to transmission service and limit security constrained least cost dispatch. Moreover, no offsetting reliability consideration has been identified and explained. The MMU is reviewing the issues in this proceeding and may offer comments on the issues raised by the Commission in Docket No. ER08-858-000, et al. and in future reports.

11 Complaint of PJM Interconnection, L.L.C., filed in EL10-60-000 at 19.

12 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed April 22, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

13 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed April 22, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2,983 KB).

14 See PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc. Docket No. ER10-713-000 (February 2, 2010).

15 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010) (Accessed April 21, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Motion_to_Intervene_and_Comments_ER10-713-000_20100225.pdf> (225 KB).

16 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM; Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc., in Docket No. ER10-713-000.

17 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed April 22, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

18 111 FERC ¶ 61,228 (2005).

19 See Docket Nos. ER08-858-000, ER08-867-000 and EL02-23-000. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

20 130 FERC ¶ 61,126 at PP 1,24 (February 19, 2010) ("The parties need to address whether these contracts are sufficiently firm to be rolled over under Order No. 888; whether, if they are eligible for rollover, Con Ed is eligible only for OATT service, or whether the circumstances here warrant a non-conforming agreement; and whether and what effect these agreements have on the rights of and prices paid by other parties, including the effect of the flow changes in the JOA on the Locational Marginal Prices in both PJM and NYISO and the effect of these provisions on the ability of other parties to transact business.").

21 *Id.*

22 See, e.g., Initial Brief in Response to Order Establishing Additional Procedures of the NRG Companies, filed in Docket No. ER08-858-000, et al.

- **Neptune Underwater Transmission Line to Long Island, New York.** On July 1, 2007, a 65-mile direct current (DC) transmission line from Sayreville, New Jersey, to Nassau County on Long Island, via undersea and underground cable, was placed in service, providing a direct connection from PJM to the New York Independent System Operator, Inc. (NYISO). This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[23] The basis for this limitation is unclear. Over the first three months of 2010, the PJM average hourly LMP at the Neptune Interface was $48.63 while the NYISO LMP at the Neptune Bus was $58.71, a difference of $10.08. The average hourly flow during the first three months of 2010 was -621 MW, which aligned with price differentials in 61 percent of all hours during the first three months of 2010.

- **Linden Variable Frequency Transformer (VFT) Facility.** On November 1, 2009, the Linden VFT facility was placed in service, providing an additional direct connection from PJM to the NYISO. A variable frequency transformer allows for fast responding continuous bidirectional power flow control, similar to that of a phase angle regulating transformer.[24] The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line, with a capacity of 300 MW. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[25] The basis for this limitation is unclear. Over the first three months of 2010, the PJM average hourly LMP at the Linden Interface was $48.87 while the NYISO LMP at the Linden Bus was $52.41, a difference of $3.53. The average hourly flow during the first three months of 2010 was -176 MW, which aligned with price differentials in 51 percent of all hours during the first three months of 2010.

Interchange Transaction Issues

- **Loop Flows.** Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. Loop flows arise from transactions on contract paths that do not correspond to the actual physical paths that the energy takes. During the first three months of 2010, net scheduled interchange was -294 GWh and net actual interchange was -231 GWh for a difference of 63 GWh or 21.4 percent. While the three month net totals reflect a large mismatch between scheduled and actual interchange, an evaluation of the monthly net flows shows that the values have been converging. A similar pattern was observed in the first quarter of 2007, when the net scheduled interchange changed from net exports to net imports, reducing the net scheduled interchange, and increasing the net difference, resulting in a difference between scheduled and actual interchange of 49.4 percent. Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

  - **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As it had in 2009, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-3,964 GWh during the first three months of 2010 and -14,441 GWh during the calendar year 2009). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (1,274 GWh during the first three months of 2010 and 3,840 GWh during the calendar year 2009). The net difference between scheduled flows and actual flows at the PJM/MECS Interface was exports while the net difference at the PJM/TVA Interface was imports.

  - **Loop Flows at PJM's Southern Interfaces.** The difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) to the west and PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK to the east) was significant during the first three months of 2010.

    The southern interfaces have historically experienced significant loop flows.[26] A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage

23 See PJM. "PJM Open Access Transmission Tariff" (October 15, 2009) (Accessed April 22, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,403 KB).

24 A phase angle regulating transformer (PAR) allows dispatchers to change the flow of MW over a transmission line by changing the impedance of the transmission facility.

25 See PJM. "PJM Open Access Transmission Tariff" (October 15, 2009) (Accessed April 22, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,884 KB).

26 See *2002 State of the Market Report*, Part 2, Section 3, "Interchange Transactions." (March 5, 2003) (Accessed April 22, 2010) <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2002/SOM2002-part2.pdf> (4,068 KB).

pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import pricing point (SouthIMP) and a single export interface pricing point (SouthEXP). At the time of the consolidation of the Southeast and Southwest Interface pricing points, some market participants requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. (The average difference between the Locational Marginal Price (LMP) at the Southeast pricing points and the SouthEXP pricing point was $4.34 during the first three months of 2010 and the average difference between LMP at the Southwest pricing points and the SouthEXP pricing point was -$3.05 during the first three months of 2010. In other words, it was more expensive to buy from PJM, for export to the south, using the old Southeast pricing point as opposed to the current SouthEXP pricing point, and less expensive to buy from PJM, for export to the south, using the old Southwest pricing point as opposed to the current SouthEXP pricing point.) These grandfathered agreements remain in place. The MMU recommends that these agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities.

- **PJM Transmission Loading Relief Procedures (TLRs).** During the first three months of 2010, PJM issued 13 TLRs. Of the 13 TLRs issued, the highest levels reached were TLR 3a for seven events and TLR 3b for the remaining six events. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces. There are several factors that affect the number of times a reliability coordinator needs to initiate a TLR and the TLR level, including market design and operating agreements. The fact that PJM has issued only 13 TLRs during the first three months of 2010 reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with the Midwest ISO. PJM's operating rules allow PJM to reconfigure the transmission system prior to reaching system operating limits that would require the need for higher level TLRs.

- **Up-To Congestion.** In the period following the March 1, 2008 modifications to the up-to congestion bids (March 1, 2008 through March 31, 2010), the monthly average of up-to congestion bidding increased from 3,027.1 GWh (for the period from January 1, 2006 through April 30, 2008) to 4,620.3 GWh.

  The up-to congestion transactions during the first three months of 2010 were comprised of 50.4 percent imports, 45.2 percent exports and 4.4 percent wheeling transactions. Only 0.4 percent of the up-to congestion transactions had matching Real-Time Market transactions. Of the up-to congestion transactions with matching Real-Time Market transactions, 0.1 percent were imports, 94.6 percent were exports and 5.3 percent were wheel through transactions.

  When the up-to congestion product was used as intended, with matching Real-Time Market transactions, 80.8 percent of the total cleared transaction MW were profitable during the first three months of 2010. The net profit on all these transactions was approximately $314,000. When up-to congestion transactions did not have a matching Real-Time Market transaction, 55.4 percent of the total cleared transaction MW were profitable. The net loss on all these transactions was approximately $18.1 million.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** When reserving non-firm transmission, the market participant has the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow.

  If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction.

  Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. The method that PJM uses to curtail not willing to pay congestion requires the transaction to be loaded. While loaded, if congestion occurs for a not willing to pay congestion transaction, a message is sent to the PJM operators requesting the transaction be curtailed at the next 15 minute interval.

The total uncollected congestion charges for the first three months of 2010 were $978,756 ($688,547 for the calendar year 2009). The MMU recommends modifying the evaluation criteria via a change to PJM's market software, to ensure that a not willing to pay congestion transaction is not permitted to flow in the presence of congestion.

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are not transparent.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities for the first three months of 2010, including evolving transaction patterns, economics and issues. During the first three months of 2010, PJM was a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 73 percent of the total real-time net exports and two interfaces accounted for 78 percent of the real-time net import volume. Four interfaces accounted for 84 percent of the total day-ahead net exports and two interfaces accounted for 89 percent of the day-ahead net import volume.

Interchange Transaction Activity

Aggregate Imports and Exports

Figure 4-1 PJM real-time scheduled imports and exports: January through March 2010 (See 2009 SOM, Figure 4-1)

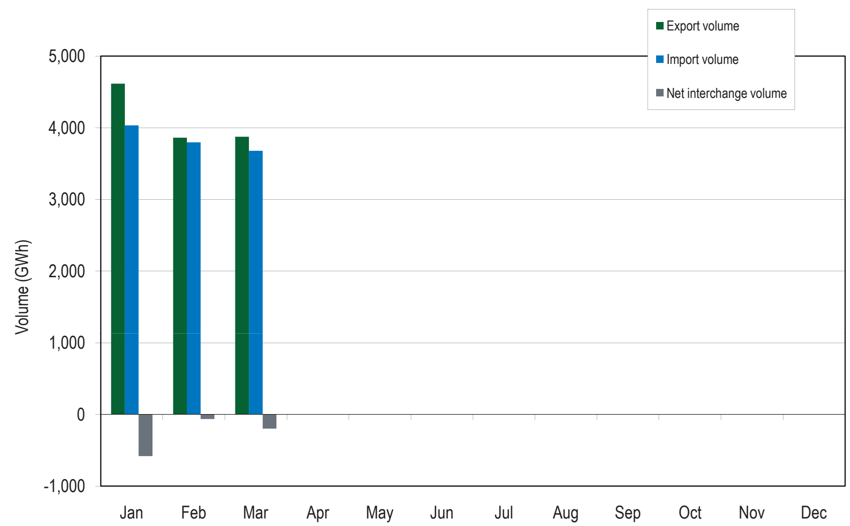


Figure 4-2 PJM day-ahead scheduled imports and exports: January through March 2010 (See 2009 SOM, Figure 4-2)

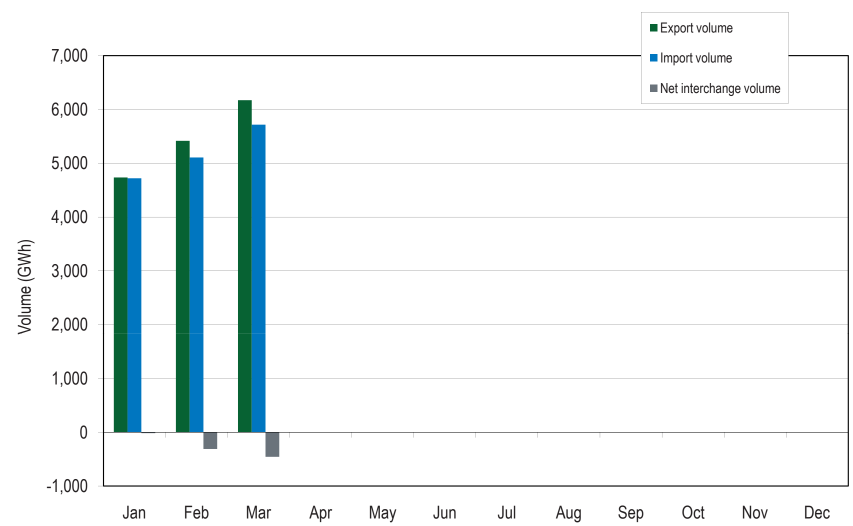
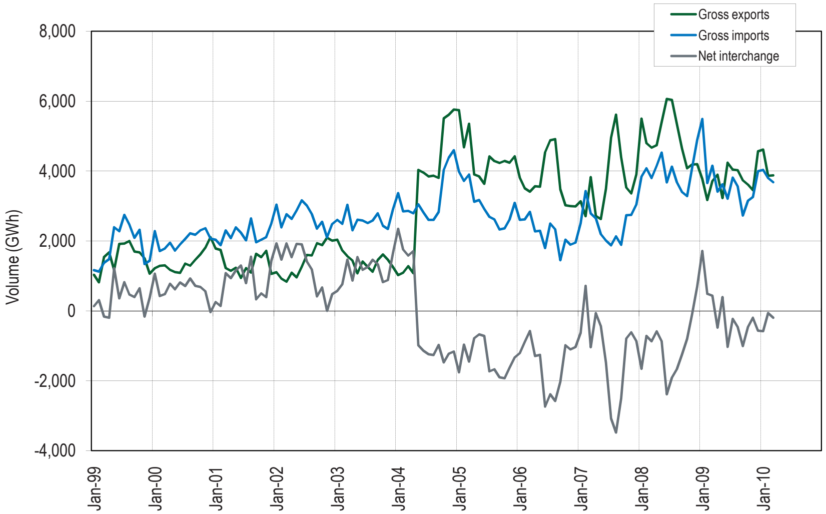


Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through March 2010 (See 2009 SOM, Figure 4-3)



Interface Imports and Exports

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): January through March 2010 (See 2009 SOM, Table 4-1)

	Jan	Feb	Mar	Total
CPLE	(70.4)	(72.8)	(40.8)	(184.0)
CPLW	0.0	0.0	0.0	0.0
DUK	219.7	92.2	(32.8)	279.1
EKPC	(65.5)	(99.2)	14.1	(150.6)
LGEE	31.9	144.5	29.7	206.1
MEC	(454.2)	(422.0)	(458.1)	(1,334.3)
MISO	(74.1)	512.4	510.7	949.0
ALTE	3.6	(9.5)	13.7	7.8
ALTW	(32.1)	(8.4)	1.4	(39.1)
AMIL	(141.6)	(85.5)	(63.5)	(290.6)
CIN	78.4	323.4	233.5	635.3
CWLP	0.0	0.0	0.0	0.0
FE	(117.4)	(60.2)	(70.6)	(248.2)
IPL	(28.4)	48.4	(4.6)	15.4
MECS	195.1	312.7	387.5	895.3
NIPS	(24.0)	(10.8)	(4.9)	(39.7)
WEC	(7.7)	2.3	18.2	12.8
NYISO	(1,307.0)	(1,039.9)	(1,109.6)	(3,456.5)
LIND	(146.0)	(125.5)	(115.7)	(387.2)
NEPT	(496.7)	(423.6)	(449.9)	(1,370.2)
NYIS	(664.3)	(490.8)	(544.0)	(1,699.1)
OVEC	1,176.9	943.0	1,018.8	3,138.7
TVA	(39.0)	(121.5)	(129.3)	(289.8)
Total	(581.7)	(63.3)	(197.3)	(842.3)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): January through March 2010 (See 2009 SOM, Table 4-2)

	Jan	Feb	Mar	Total
CPLE	128.3	113.4	99.8	341.5
CPLW	0.0	0.0	0.0	0.0
DUK	408.5	235.2	135.1	778.8
EKPC	15.8	3.0	53.9	72.7
LGEE	48.9	150.5	73.5	272.9
MEC	44.1	28.1	35.7	107.9
MISO	1,142.9	1,388.4	1,292.1	3,823.4
ALTE	30.0	8.0	28.9	66.9
ALTW	0.0	5.4	7.6	13.0
AMIL	23.5	49.2	39.2	111.9
CIN	500.9	555.4	454.8	1,511.1
CWLP	0.0	0.0	0.0	0.0
FE	181.6	207.6	205.4	594.6
IPL	47.1	116.7	16.2	180.0
MECS	304.3	385.9	475.1	1,165.3
NIPS	0.0	0.0	0.0	0.0
WEC	55.5	60.2	64.9	180.6
NYISO	934.4	901.2	922.5	2,758.1
LIND	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0
NYIS	934.4	901.2	922.5	2,758.1
OVEC	1,176.9	943.0	1,018.8	3,138.7
TVA	134.6	35.7	47.7	218.0
Total	4,034.4	3,798.5	3,679.1	11,512.0

Table 4-3 Real-time scheduled gross export volume by interface (GWh): January through March 2010 (See 2009 SOM, Table 4-3)

	Jan	Feb	Mar	Total
CPLE	198.7	186.2	140.6	525.5
CPLW	0.0	0.0	0.0	0.0
DUK	188.8	143.0	167.9	499.7
EKPC	81.3	102.2	39.8	223.3
LGEE	17.0	6.0	43.8	66.8
MEC	498.3	450.1	493.8	1,442.2
MISO	1,217.0	876.0	781.4	2,874.4
ALTE	26.4	17.5	15.2	59.1
ALTW	32.1	13.8	6.2	52.1
AMIL	165.1	134.7	102.7	402.5
CIN	422.5	232.0	221.3	875.8
CWLP	0.0	0.0	0.0	0.0
FE	299.0	267.8	276.0	842.8
IPL	75.5	68.3	20.8	164.6
MECS	109.2	73.2	87.6	270.0
NIPS	24.0	10.8	4.9	39.7
WEC	63.2	57.9	46.7	167.8
NYISO	2,241.4	1,941.1	2,032.1	6,214.6
LIND	146.0	125.5	115.7	387.2
NEPT	496.7	423.6	449.9	1,370.2
NYIS	1,598.7	1,392.0	1,466.5	4,457.2
OVEC	0.0	0.0	0.0	0.0
TVA	173.6	157.2	177.0	507.8
Total	4,616.1	3,861.8	3,876.4	12,354.3

Table 4-4 Day-ahead net interchange volume by interface (GWh): January through March 2010 (See 2009 SOM, Table 4-4)

	Jan	Feb	Mar	Total
CPLE	(89.3)	(111.3)	(114.7)	(315.3)
CPLW	10.2	(1.0)	1.0	10.2
DUK	161.4	38.4	8.6	(214.4)
EKPC	(1.5)	(5.9)	(3.4)	(60.1)
LGEE	1.0	5.3	0.0	(33.2)
MEC	(479.4)	(444.1)	(482.8)	(3,374.0)
MISO	282.3	(160.5)	(312.1)	(190.3)
ALTE	227.6	(257.5)	(136.2)	(166.1)
ALTW	(282.2)	(414.3)	(1,220.9)	(1,917.4)
AMIL	14.4	97.5	6.7	118.6
CIN	182.9	(60.8)	43.1	165.2
CWLP	0.0	0.0	0.0	0.0
FE	(70.5)	(20.7)	118.8	27.6
IPL	(53.4)	(18.4)	(44.7)	(116.5)
MECS	387.8	654.4	885.6	1,927.8
NIPS	(204.5)	(217.0)	(143.3)	(564.8)
WEC	80.2	76.3	178.8	335.3
NYISO	(969.0)	(912.0)	(825.4)	(2,706.4)
LIND	(21.1)	(18.3)	(53.2)	(92.6)
NEPT	(502.6)	(445.2)	(456.7)	(1,404.5)
NYIS	(445.3)	(448.5)	(315.5)	(1,209.3)
OVEC	1,074.0	1,243.3	1,300.5	3,617.8
TVA	(5.3)	37.8	(27.0)	5.5
Total	(15.6)	(310.0)	(455.3)	(780.9)

Table 4-5 Day-ahead gross import volume by interface (GWh): January through March 2010 (See 2009 SOM, Table 4-5)

	Jan	Feb	Mar	Total
CPLE	64.2	39.5	29.3	133.0
CPLW	15.6	0.6	1.8	18.0
DUK	176.3	96.2	48.1	320.6
EKPC	0.0	0.0	0.4	0.4
LGEE	1.0	5.4	0.0	6.4
MEC	18.8	5.6	12.2	36.6
MISO	2,400.5	2,738.3	3,112.5	8,251.3
ALTE	866.4	762.4	662.8	2,291.6
ALTW	72.0	67.2	72.4	211.6
AMIL	68.1	157.9	50.5	276.5
CIN	436.8	592.0	555.1	1,583.9
CWLP	0.0	0.0	0.0	0.0
FE	156.2	176.9	364.9	698.0
IPL	26.9	29.4	30.7	87.0
MECS	606.2	801.7	1,125.2	2,533.1
NIPS	28.6	19.5	24.3	72.4
WEC	139.3	131.3	226.6	497.2
NYISO	835.3	885.1	1,095.7	2,816.1
LIND	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0
NYIS	835.3	885.1	1,095.7	2,816.1
OVEC	1,133.2	1,259.7	1,379.9	3,772.8
TVA	75.9	77.8	36.7	190.4
Total	4,720.8	5,108.2	5,716.6	15,545.6

Table 4-6 Day-ahead gross export volume by interface (GWh): January through March 2010 (See 2009 SOM, Table 4-6)

	Jan	Feb	Mar	Total
CPLE	153.5	150.8	144.0	448.3
CPLW	5.4	1.6	0.8	7.8
DUK	14.9	57.8	39.5	535.0
EKPC	1.5	5.9	3.8	60.5
LGEE	0.0	0.1	0.0	39.6
MEC	498.2	449.7	495.0	3,410.6
MISO	2,118.2	2,898.8	3,424.6	8,441.6
ALTE	638.8	1,019.9	799.0	2,457.7
ALTW	354.2	481.5	1,293.3	2,129.0
AMIL	53.7	60.4	43.8	157.9
CIN	253.9	652.8	512.0	1,418.7
CWLP	0.0	0.0	0.0	0.0
FE	226.7	197.6	246.1	670.4
IPL	80.3	47.8	75.4	203.5
MECS	218.4	147.3	239.6	605.3
NIPS	233.1	236.5	167.6	637.2
WEC	59.1	55.0	47.8	161.9
NYISO	1,804.3	1,797.1	1,921.1	5,522.5
LIND	21.1	18.3	53.2	92.6
NEPT	502.6	445.2	456.7	1,404.5
NYIS	1,280.6	1,333.6	1,411.2	4,025.4
OVEC	59.2	16.4	79.4	155.0
TVA	81.2	40.0	63.7	184.9
Total	4,736.4	5,418.2	6,171.9	16,326.5

Interface Pricing

Table 4-7 Active interfaces: January through March 2010 (See 2009 SOM, Table 4-7)

	Jan	Feb	Mar
ALTE	Active	Active	Active
ALTW	Active	Active	Active
AMIL	Active	Active	Active
CIN	Active	Active	Active
CPLE	Active	Active	Active
CPLW	Active	Active	Active
CWLP	Active	Active	Active
DUK	Active	Active	Active
EKPC	Active	Active	Active
FE	Active	Active	Active
IPL	Active	Active	Active
LGEE	Active	Active	Active
LIND	Active	Active	Active
MEC	Active	Active	Active
MECS	Active	Active	Active
NEPT	Active	Active	Active
NIPS	Active	Active	Active
NYIS	Active	Active	Active
OVEC	Active	Active	Active
TVA	Active	Active	Active
WEC	Active	Active	Active

Figure 4-4 PJM's footprint and its external interfaces (See 2009 SOM, Figure 4-4)

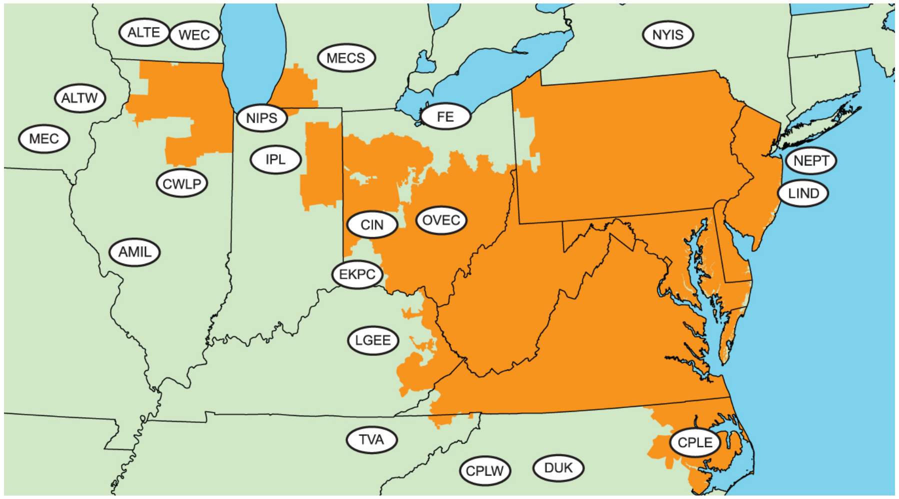


Table 4-8 Active pricing points: January through March 2010 (See 2009 SOM, Table 4-8)

PJM 2010 Pricing Points (January through March)			
LIND	MICHFE	MISO	NEPT
NIPSCO	Northwest	NYIS	Ontario IESO
OVEC	SOUTHEXP	SOUTHIMP	

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

PJM and Midwest ISO Interface Prices

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): January through March 2010 (See 2009 SOM, Figure 4-5)

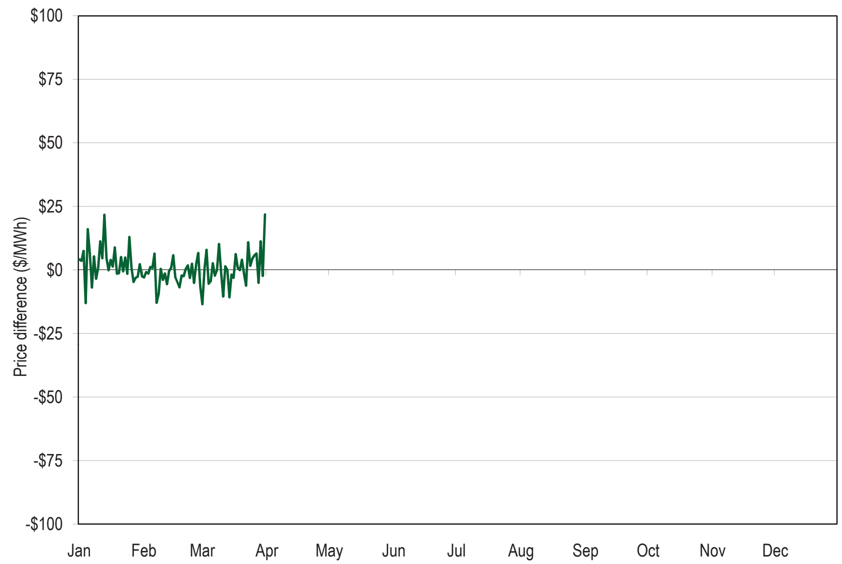


Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through March 2010 (See 2009 SOM, Figure 4-6)

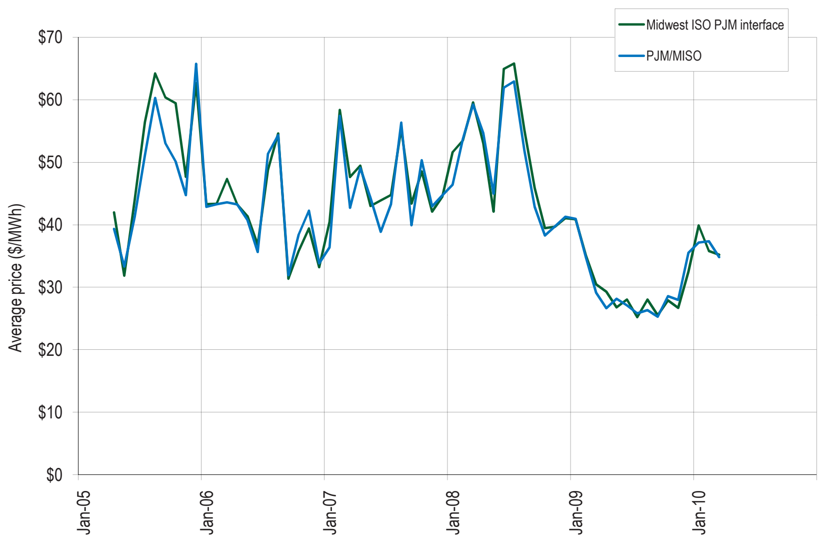


Figure 4-7 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): January through March 2010 (See 2009 SOM, Table 4-7)

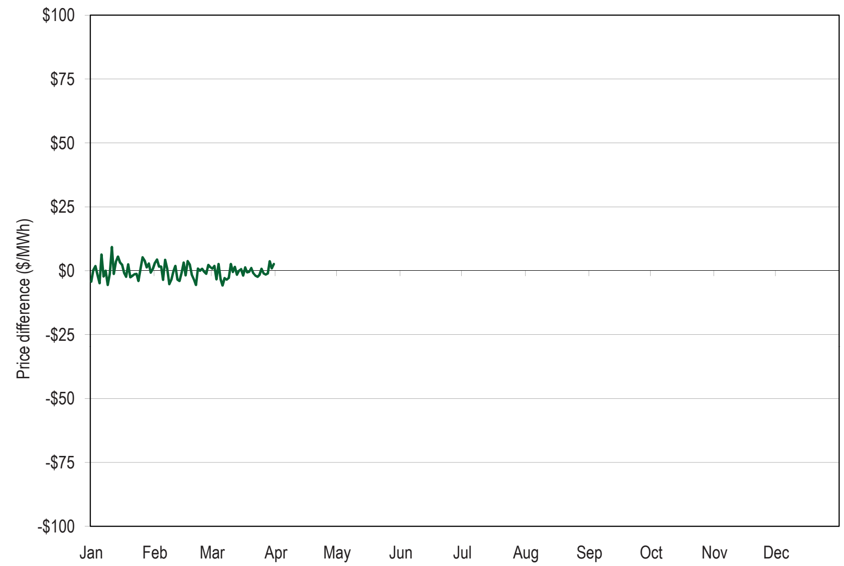


Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): January 1, 2008 through March 31, 2010 (See 2009 SOM, Table 4-9)

	2008			2009			2010		
	LMP	MCC	MLC	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$8.26	($6.56)	($2.86)	$4.81	($2.65)	($2.06)	$2.41	($4.85)	($2.85)
Beaver Valley (PJM) & Mansfield (MISO)	$0.89	($14.42)	($2.38)	$3.22	($4.92)	($1.38)	$1.50	($6.67)	($1.95)
Miami Fort (PJM) & (MISO)	$1.25	($12.27)	($4.16)	$2.20	($4.64)	($2.70)	$1.93	($4.67)	($3.51)
Stuart (PJM) & (MISO)	$0.87	($12.04)	($4.77)	$1.81	($4.63)	($3.07)	$1.49	($4.70)	($3.92)
PJM/MISO Interface	($1.16)	($15.34)	($3.51)	$0.01	($6.94)	($2.58)	($0.38)	($7.07)	($3.42)
LMP: Locational Marginal Price, MCC: Marginal Congestion Component, MLC: Marginal Loss Component									

Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through March 2010 (See 2009 SOM, Table 4-8)

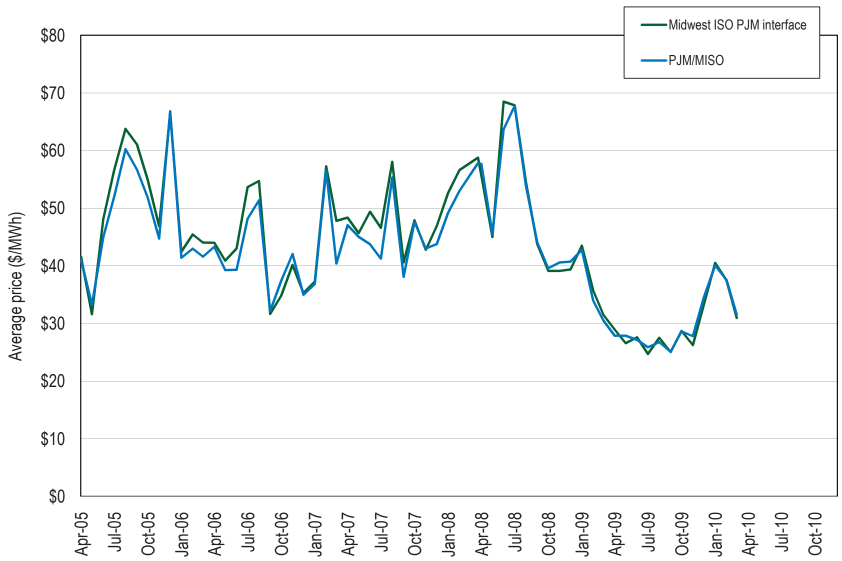


Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): January 1, 2008 through March 31, 2010 (See 2009 SOM, Table 4-10)

	2008			2009			2010		
	LMP	MCC	MLC	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$9.19	($3.00)	($4.25)	$4.02	($2.06)	($2.80)	$1.41	($5.77)	($3.28)
Beaver Valley (PJM) & Mansfield (MISO)	$3.40	($9.88)	($3.16)	$2.48	($4.72)	($1.67)	$1.33	($6.90)	($2.24)
Miami Fort (PJM) & (MISO)	($0.05)	($11.17)	($5.32)	$1.87	($3.85)	($3.16)	$1.15	($5.05)	($4.26)
Stuart (PJM) & (MISO)	($0.56)	($11.00)	($6.00)	$1.40	($3.87)	($3.61)	$0.58	($5.07)	($4.81)
PJM/MISO Interface	($0.62)	($12.51)	($4.55)	($0.03)	($5.75)	($3.16)	$0.07	($6.25)	($4.14)
LMP: Locational Marginal Price, MCC: Marginal Congestion Component, MLC: Marginal Loss Component									

PJM and NYISO Interface Prices

Figure 4-9 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): January through March 2010 (See 2009 SOM, Figure 4-9)

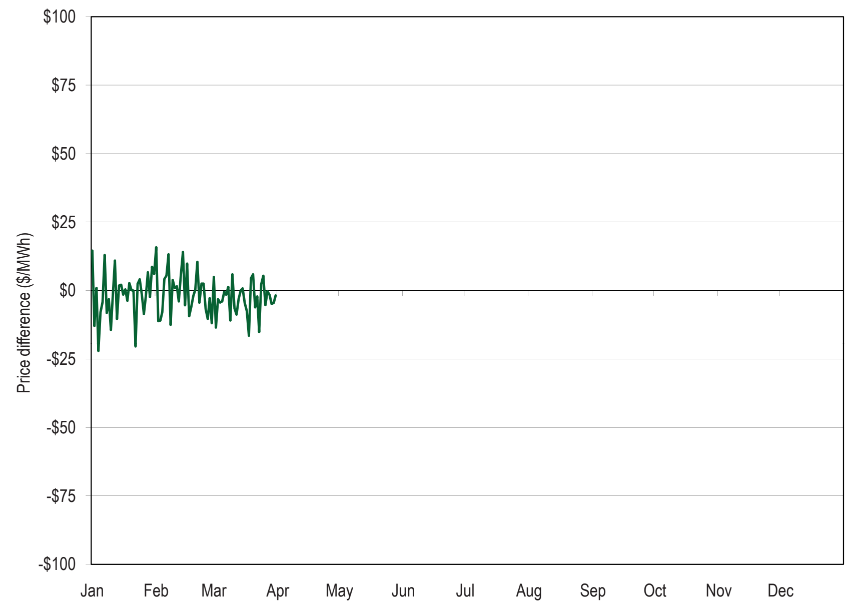


Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through March 2010 (See 2009 SOM, Figure 4-10)

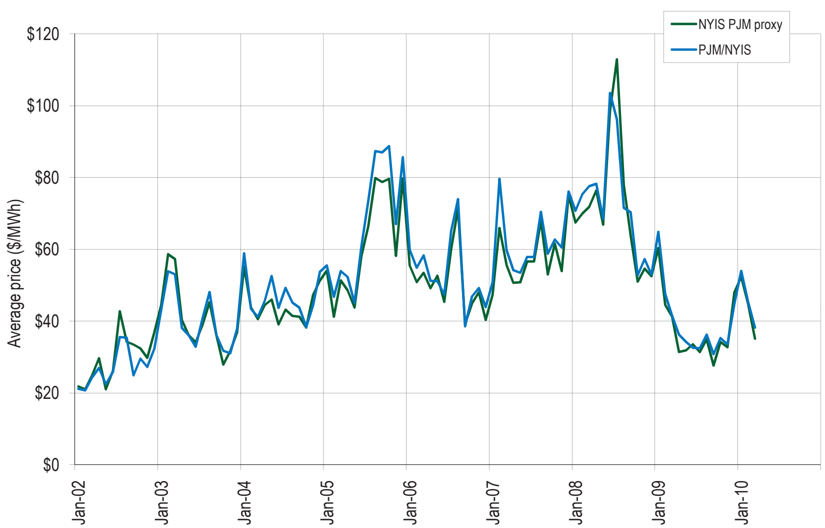


Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through March 2010 (See 2009 SOM, Table 4-11)

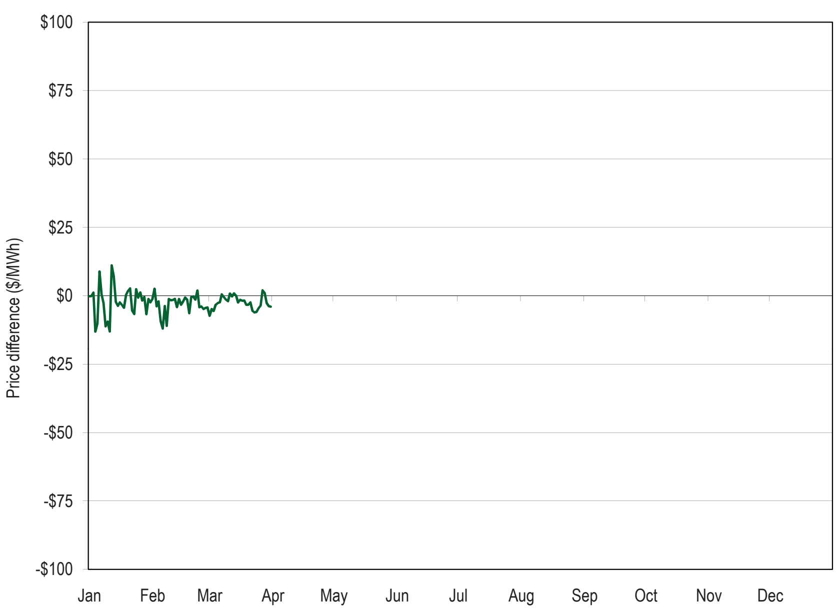
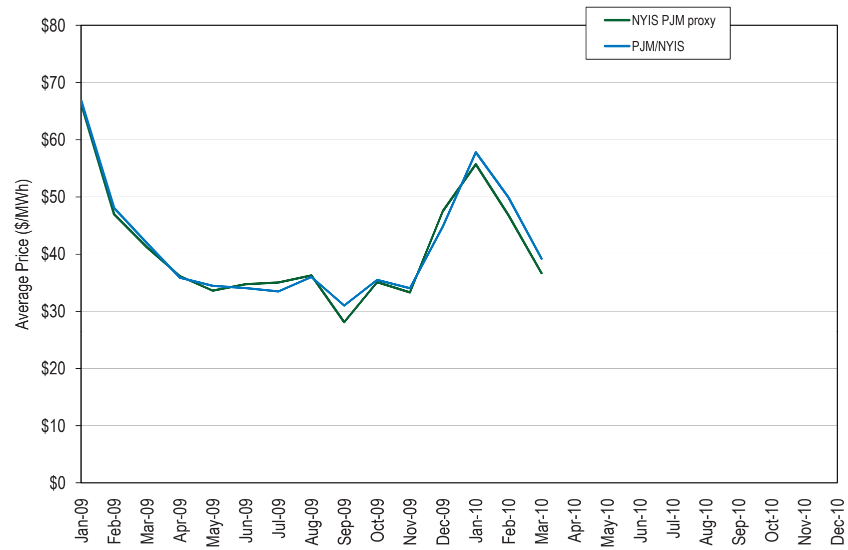


Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2009 through March 2010 (See 2009 SOM, Figure 4-12)



Summary of Interface Prices between PJM and Organized Markets

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: January through March 2010 (See 2009 SOM, Figure 4-13)

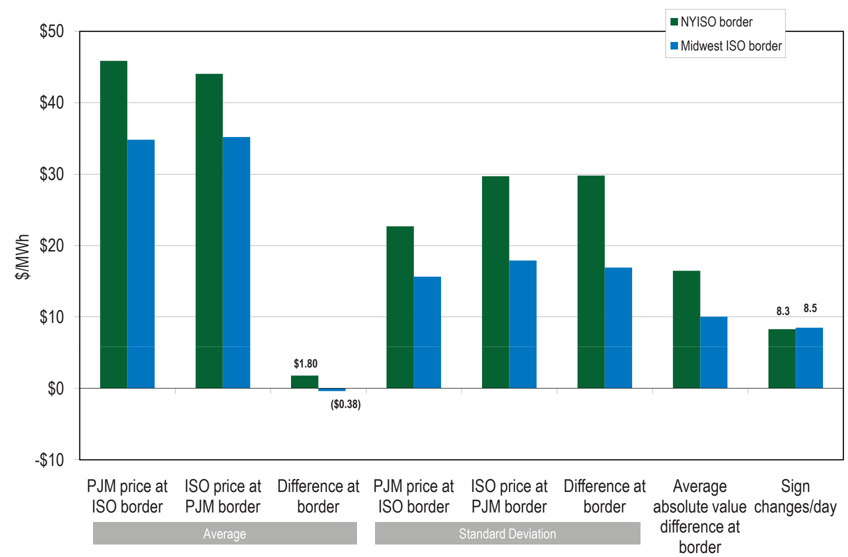
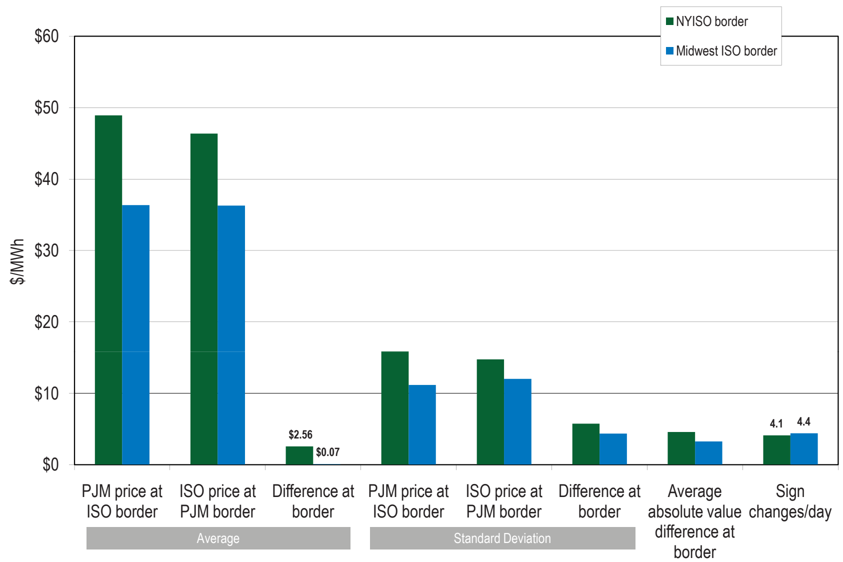


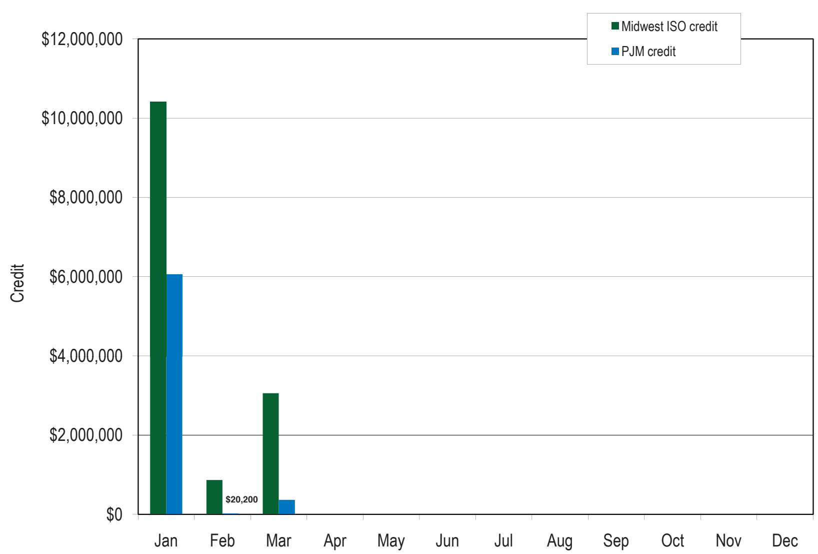
Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: January through March 2010 (See 2009 SOM, Figure 4-14)



Operating Agreements with Bordering Areas

PJM and Midwest ISO Joint Operating Agreement

Figure 4-15 Credits for coordinated congestion management: January through March 2010 (See 2009 SOM, Figure 4-15)



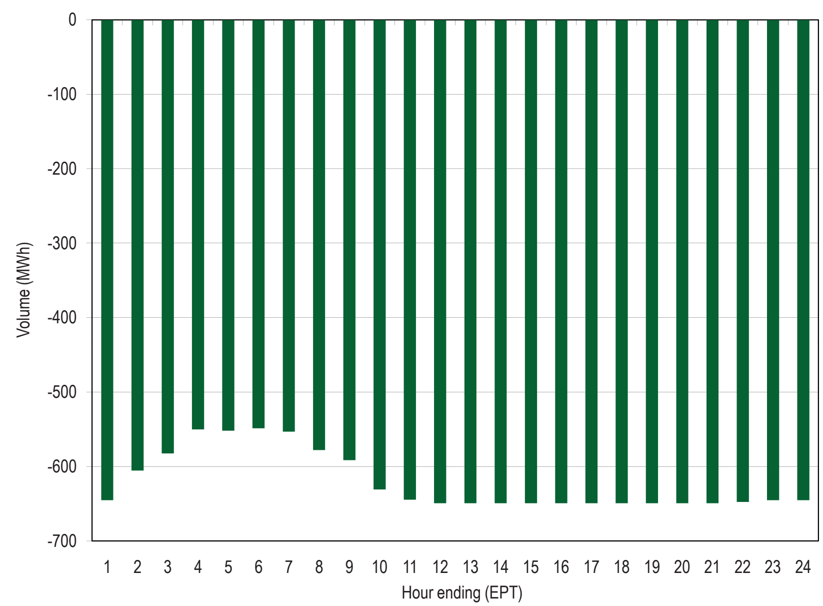
Con Edison and PSE&G Wheeling Contracts

Table 4-11 Con Edison and PSE&G wheeling settlement data: January through March 2010 (See 2009 SOM, Table 4-11)

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total Congestion Credit	$1,760,260	($26,446)	$1,733,814	$2,664,348	$0	$2,664,348
Congestion Credit			$1,333,227			$2,519,586
Adjustments			$0			($971)
Net Charge			$400,588			$145,732

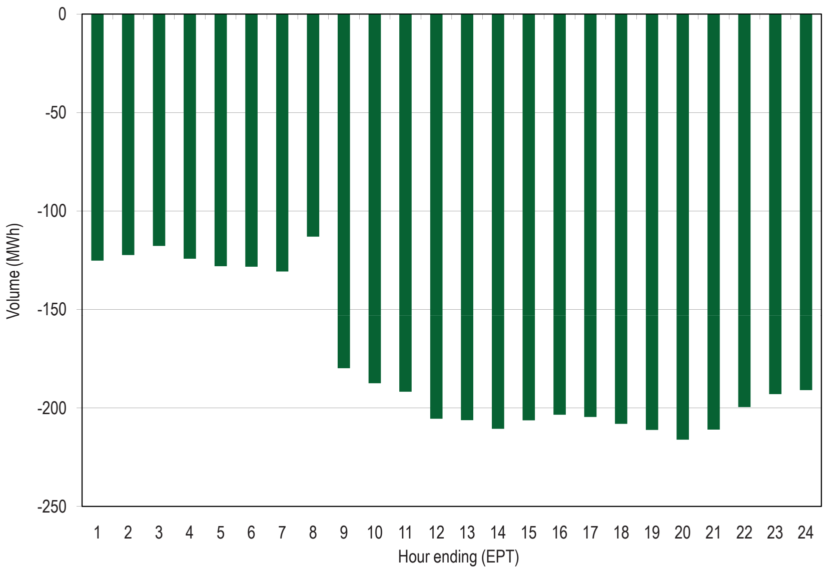
Neptune Underwater Transmission Line to Long Island, New York

Figure 4-16 Neptune hourly average flow: January through March 2010 (See 2009 SOM, Figure 4-16)



Linden Variable Frequency Transformer (VFT) facility

Figure 4-17 Linden hourly average flow: January through March 2010 (See 2009 SOM, Figure 4-17)



Interchange Transaction Issues

Loop Flows

Table 4-12 Net scheduled and actual PJM interface flows (GWh): January through March 2010 (See 2009 SOM, Table 4-12)

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	2,552	98	2,454	2504%
CPLW	(472)	-	(472)	0%
DUK	(586)	279	(865)	(310%)
EKPC	48	(151)	199	(132%)
LGEE	353	206	147	71%
MEC	(773)	(1,333)	560	(42%)
MISO	(2,264)	1,229	(3,493)	(284%)
ALTE	(1,527)	8	(1,535)	(19188%)
ALTW	(561)	(39)	(522)	1338%
AMIL	1,153	(315)	1,468	(466%)
CIN	1,088	1,237	(149)	(12%)
CWLP	(25)	-	(25)	0%
FE	(455)	(545)	90	(17%)
IPL	716	15	701	4673%
MECS	(3,069)	895	(3,964)	(443%)
NIPS	(550)	(40)	(510)	1275%
WEC	966	13	953	7331%
NYISO	(2,269)	(3,471)	1,202	(35%)
LIND	(379)	(379)	-	0%
NEPT	(1,342)	(1,342)	-	0%
NYIS	(548)	(1,750)	1,202	(69%)
OVEC	2,196	3,139	(943)	(30%)
TVA	984	(290)	1,274	(439%)
Total	(231)	(294)	63	(21.4%)

Loop Flows at PJM's Southern Interfaces

Figure 4-18 Southwest actual and scheduled flows: January 2006 through March 2010 (See 2009 SOM, Figure 4-18)

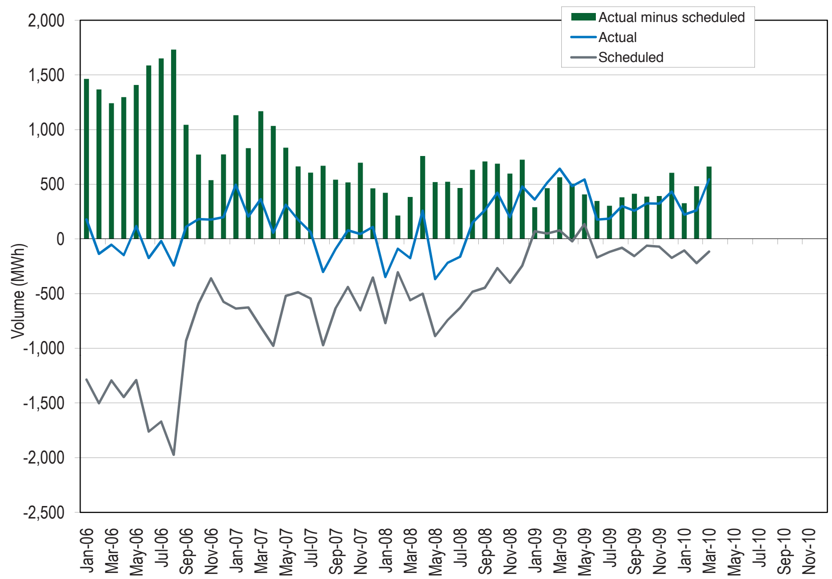
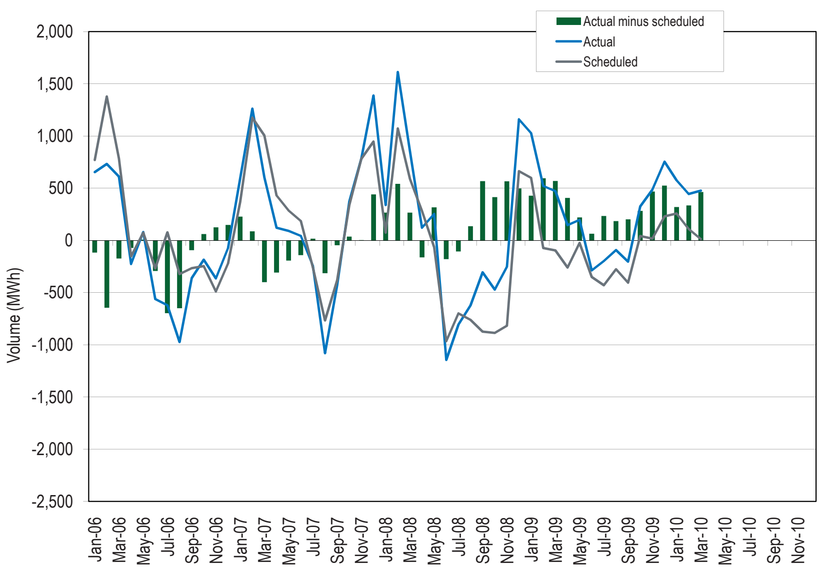


Figure 4-19 Southeast actual and scheduled flows: January 2006 through March 2010 (See 2009 SOM, Figure 4-19)



TLRs

Figure 4-20 PJM and Midwest ISO TLR procedures: Calendar year 2009 and January through March 2010 (See 2009 SOM, Figure 4-20)

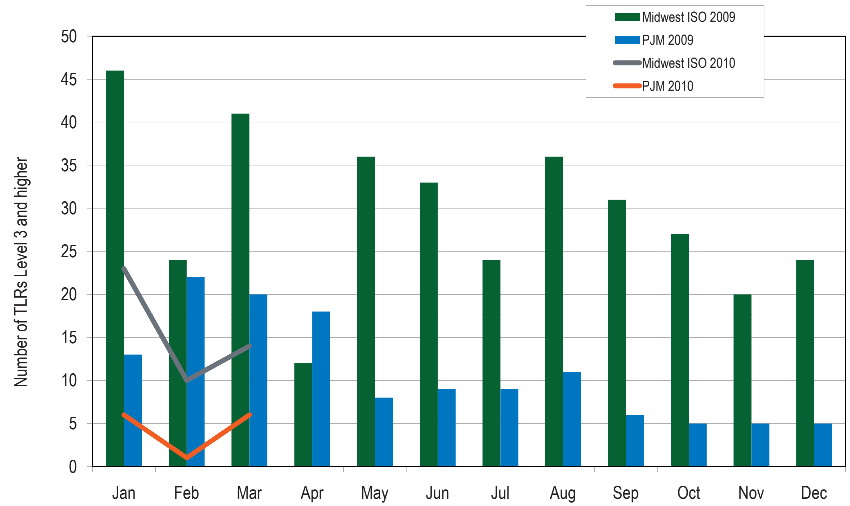


Figure 4-21 Number of different PJM flowgates that experienced TLRs: Calendar year 2009 and January through March 2010 (See 2009 SOM, Figure 4-21)

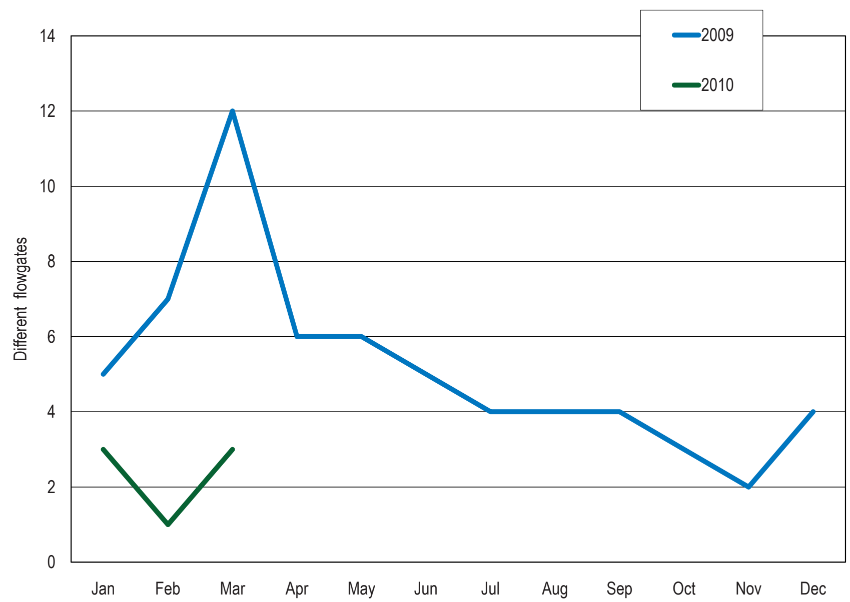


Figure 4-22 Number of PJM TLRs and curtailed volume: January through March 2010 (See 2009, Figure 4-22)

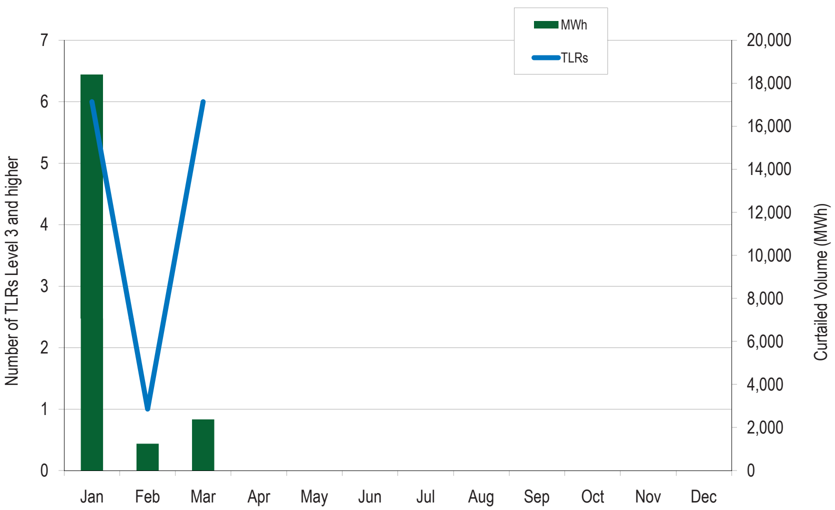


Table 4-13 Number of TLRs by TLR level by reliability coordinator: January through March 2010 (See 2009 SOM, Table 4-13)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2010	ICTE	11	4	20	2	0	0	37
	MISO	32	12	0	4	2	0	50
	NYIS	60	0	0	0	0	0	60
	ONT	18	1	0	0	0	0	19
	PJM	7	6	0	0	0	0	13
	SWPP	47	287	6	9	7	0	356
	TVA	2	4	0	0	0	0	6
Total		177	314	26	15	9	0	541

Up-To Congestion

Figure 4-23 Monthly up-to congestion bids in MWh: January 2006 through March 2010 (See 2009 SOM, Figure 4-23)

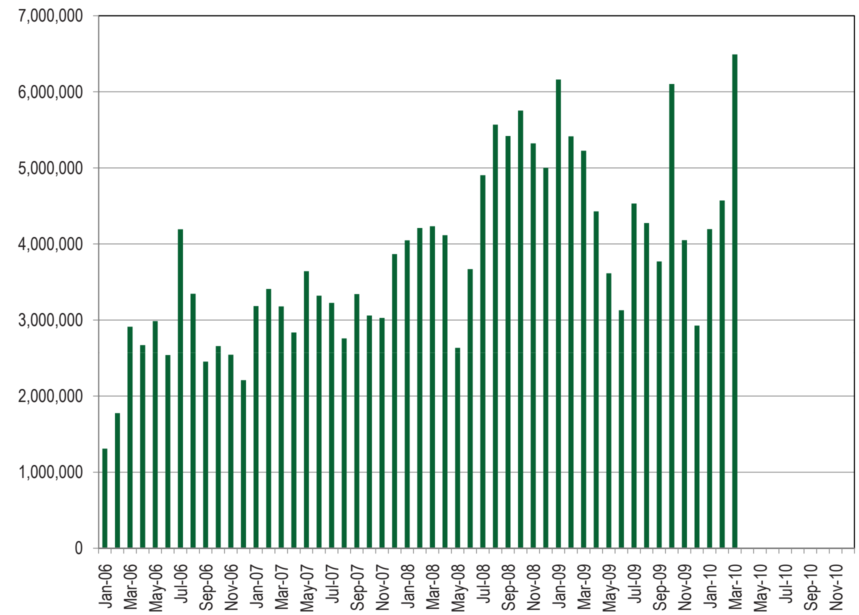


Table 4-14 Up-to congestion MW by Import, Export and Wheels: January 2006 through March 2010 (See 2009 SOM, Table 4-14)

	Import MW	Export MW	Wheeling MW	Total MW	Percent Imports	Percent Exports	Percent Wheels
2006	10,730,659	20,398,833	468,648	31,598,141	34.0%	64.6%	1.5%
2007	13,950,514	24,080,803	817,237	38,848,554	35.9%	62.0%	2.1%
2008	20,889,972	32,351,960	1,632,874	54,874,806	38.1%	59.0%	3.0%
2009	24,455,358	27,722,740	1,453,553	53,631,651	45.6%	51.7%	2.7%
2010	7,696,350	6,895,256	666,001	15,257,607	50.4%	45.2%	4.4%
TOTAL	77,722,854	111,449,592	5,038,312	194,210,758	40.0%	57.4%	2.6%

Figure 4-24 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Market transaction: January through March 2010 (See 2009 SOM, Figure 4-24)

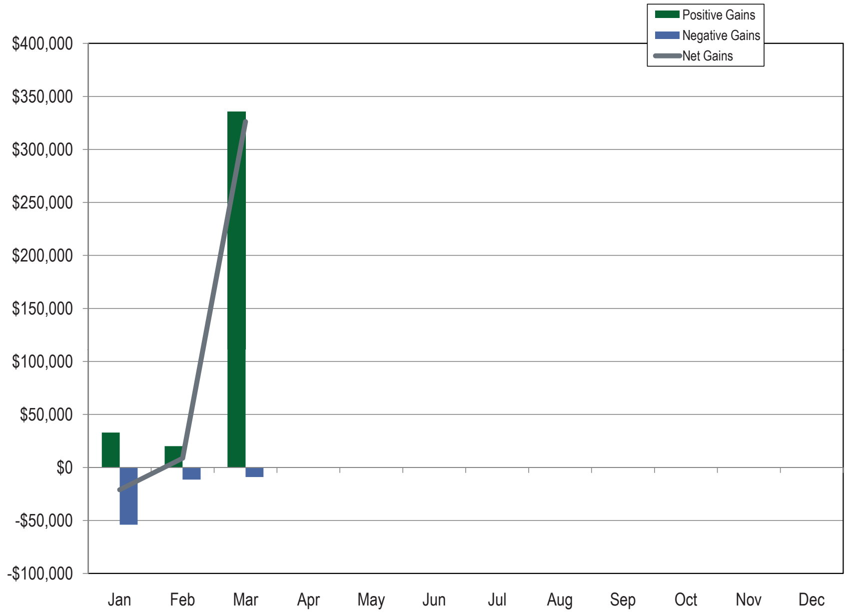
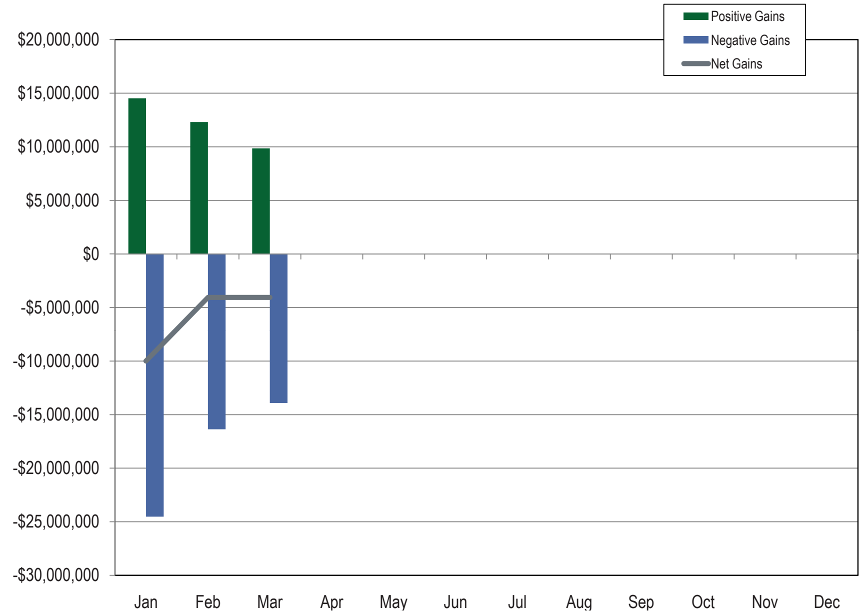


Figure 4-25 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Market transaction: January through March 2010 (See 2009 SOM, Figure 4-25)



Interface Pricing Agreements with Individual Companies

Table 4-15 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through March 2010 (See 2009 SOM, Table 4-15)

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2006	$42.55	$37.89	$38.36	$42.02	$4.20	($0.47)	$0.53	($4.13)
2007	$54.35	$45.48	$49.09	$48.48	$5.26	($3.61)	$5.87	($3.01)
2008	$62.97	$51.43	$55.47	$55.44	$7.50	($4.05)	$7.53	($4.01)
2009	$35.97	$31.94	$33.37	$33.37	$2.61	($1.42)	$2.61	($1.42)
2010	$44.59	$37.20	$40.25	$40.25	$4.34	($3.05)	$4.34	($3.05)

Table 4-16 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through March 2010 (See 2009 SOM, Table 4-17)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$43.30	$43.94	$40.25	$40.25	$3.05	$3.69
PEC	$43.61	$45.60	$40.25	$40.25	$3.37	$5.35
NCMPA	$43.55	$43.66	$40.25	$40.25	$3.30	$3.41

Figure 4-26 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through March 2010 (See 2009 SOM, Figure 4-26)

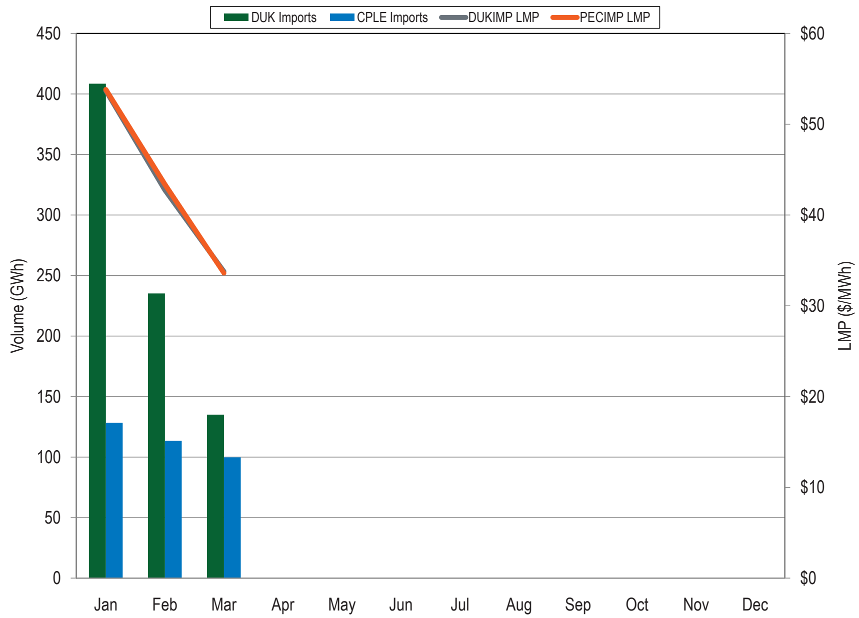


Figure 4-27 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through March 2010 (See 2009 SOM, Figure 4-27)

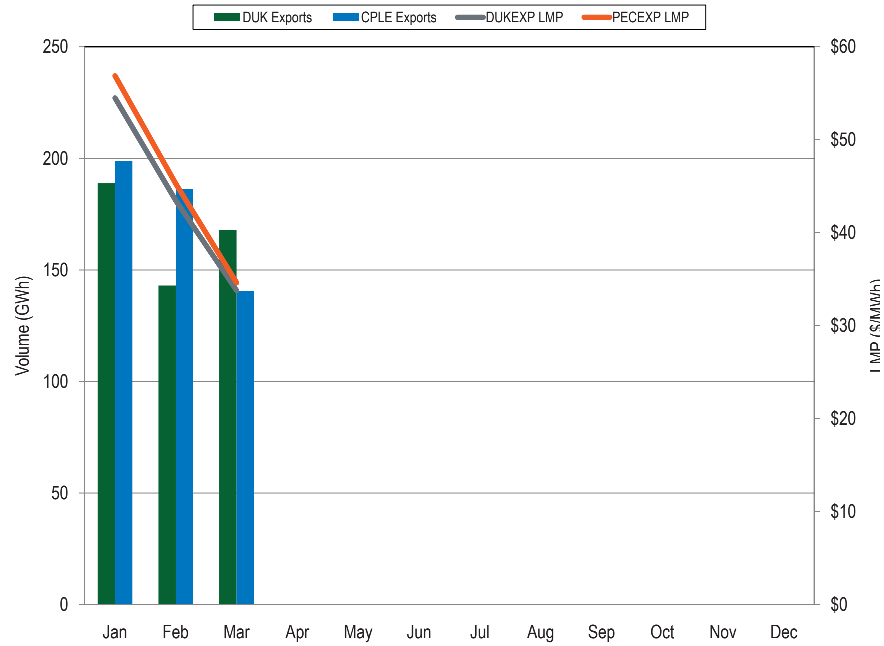


Table 4-17 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through March 2010 (See 2009 SOM, Table 4-19)

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$45.27	$46.83	$41.63	$41.63	$3.64	$5.19
PEC	$46.06	$48.61	$41.63	$41.63	$4.42	$6.98
NCMPA	$45.86	$46.02	$41.63	$41.63	$4.22	$4.38

Figure 4-28 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through March 2010 (See 2009 SOM, Figure 4-28)

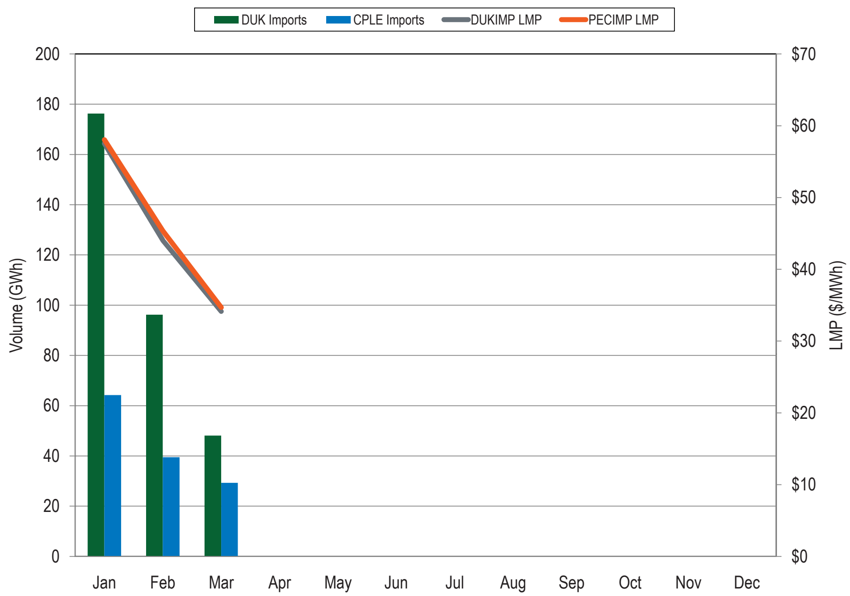
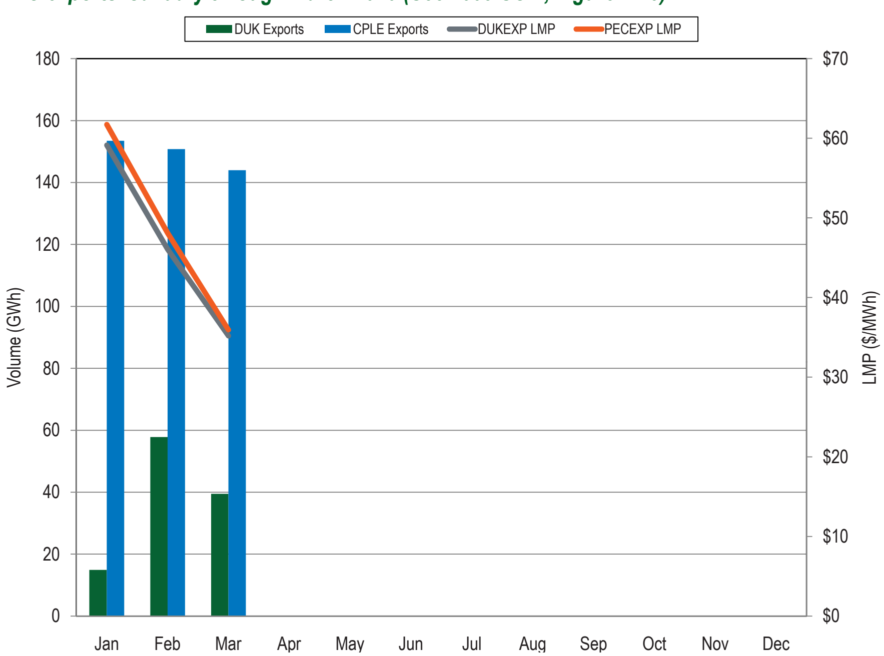
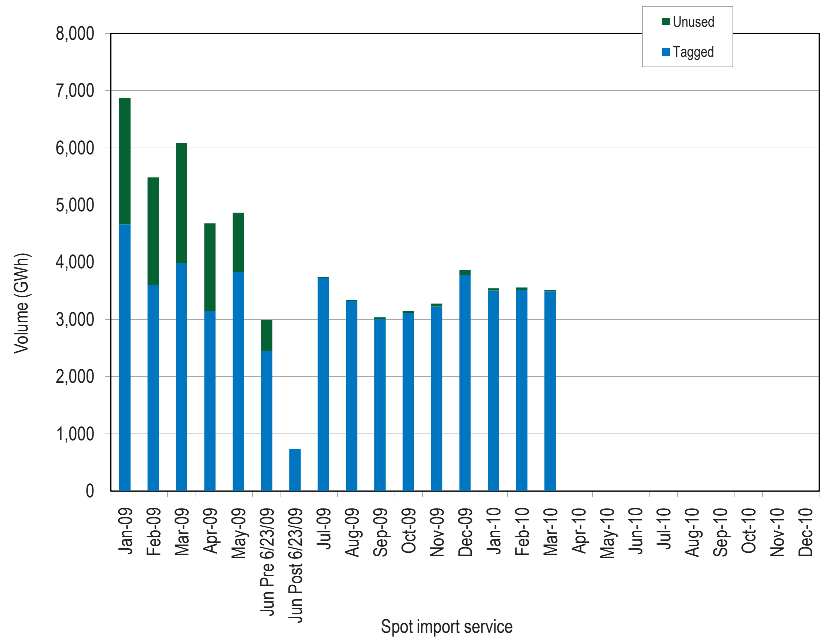


Figure 4-29 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through March 2010 (See 2009 SOM, Figure 4-29)



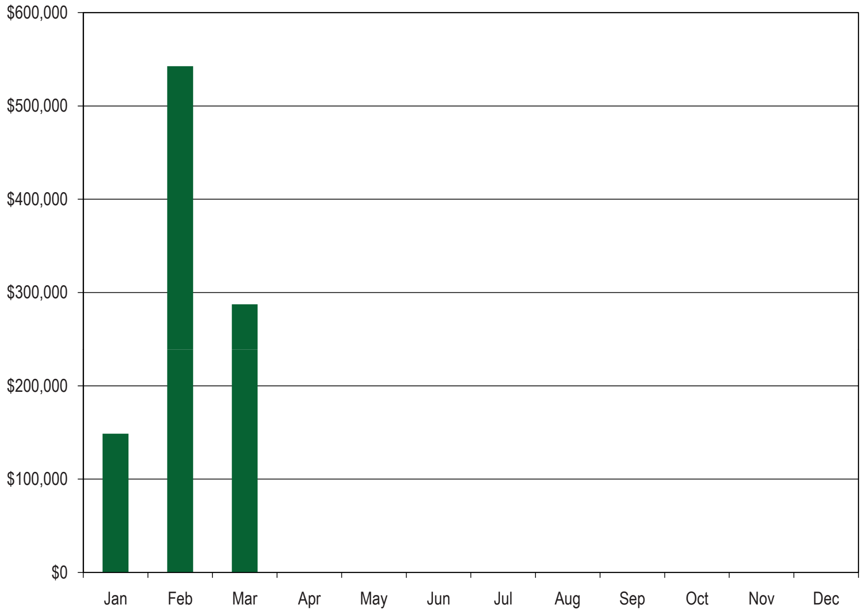
Spot Import

Figure 4-30 Spot import service utilization: January 2009 through March 2010 (See 2009 SOM, Figure 4-30)



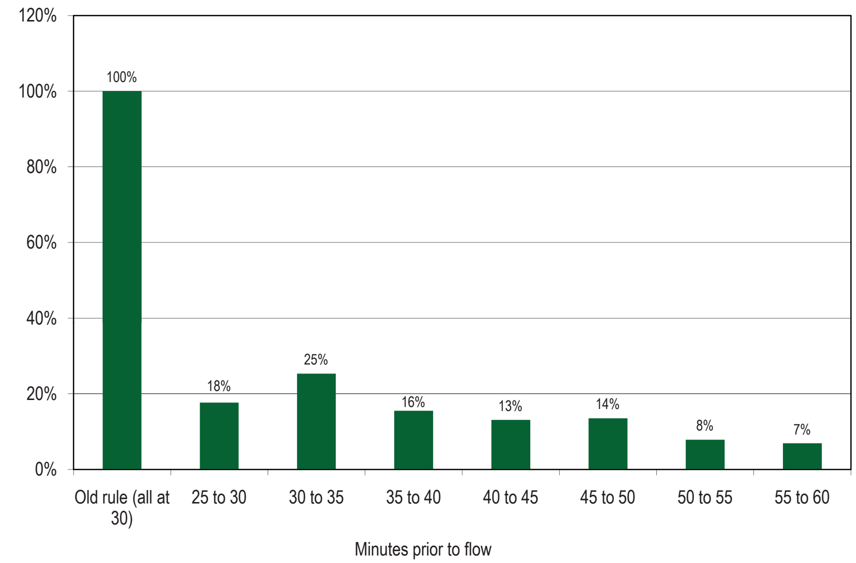
Willing to Pay Congestion and Not Willing to Pay Congestion

Figure 4-31 Monthly uncollected congestion charges: January through March 2010 (See 2009 SOM, Figure 4-31)



Ramp Availability

Figure 4-32 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through March 2010 (See 2009 SOM, Figure 4-32)



SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering them into the capacity market.

Overview

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first three months of calendar year 2010, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

RPM Capacity Market

Market Design

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region, replacing the Capacity Credit Market (CCM) design that had been in place since 1999.[1] The RPM design represents a significant change in the structure of the Capacity Market in PJM. The RPM is a forward-looking, annual, locational market, with a must offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 delivery year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[2] Prior to the 2012/2013 delivery year, the second incremental auction is conducted if PJM determines than an unforced capacity resource shortage exceeds 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[3] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13, and four months, respectively, prior to the delivery year. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.

RPM prices are locational and may vary depending on transmission constraints.[4] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity and that have flexible criteria for competitive offers by new entrants or by entrants that have an incentive to exercise monopsony power. Demand-side resources and Energy Efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **Supply.** Total internal capacity increased 350.2 MW from 156,968.0 MW on June 1, 2008, to 157,318.2 MW on June 1, 2009.[5] This increase was the result of 439.2 MW of new generation, 74.1 MW of generation uprates, 220.6 MW of demand resource (DR) modifications (mods),

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2010 Quarterly State of the Market Report for PJM: January through March*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.

2 126 FERC ¶ 61,275 (2009).

3 *PJM Interconnection, L.L.C.*, OATT Revisions, Docket No. ER10-366-000 (December 1, 2009).

4 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

5 Unless otherwise specified, all volumes are in terms of UCAP.

and a decrease of 383.7 MW due to higher Equivalent Demand Forced Outage Rates (EFORds).

In the 2010/2011, 2011/2012, and 2012/2013 auctions, new generation increased 3,271.9 MW; 651.9 MW came out of retirement and net generation deratings were 2,994.9 MW, for a total of 928.9 MW. DR and EE offers increased 9,409.3 MW through June 1, 2012. A decrease of 890.3 MW was due to higher EFORds. The reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity. The net effect from June 1, 2009, through June 1, 2012, was an increase in total internal capacity of 12,635.1 MW (8.0 percent) from 157,318.2 MW to 169,953.3 MW.

In the 2009/2010 auction, 17 more generating resources made offers than in the 2008/2009 RPM Auction. The increase consisted of 11 new resources (439.2 MW), nine resources that were previously entirely FRR committed (82.5 MW), two less resources exported (698.6 MW), and two fewer resources excused from offering into the auction (37.3 MW) offset by five excused resources (44.5 MW), one less external resource that did not offer (60.4 MW), and one additional resource committed fully to FRR (10.0 MW). The new resources consisted of eight new combustion turbine (CT) resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW).

In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The increase consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new resources consisted of seven CT resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW).

In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The increase consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

In the 2012/2013 auction, eight more generating resources made offers than in the 2011/2012 RPM auction. The net increase of eight resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[6] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two CT resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new units consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW).

- **Demand.** There was a 2,545.5 MW increase in the RPM reliability requirement from 150,934.6 MW on June 1, 2008 to 153,480.1 MW on June 1, 2009. On June 1, 2009, PJM Electric Distribution Companies (EDCs) and their affiliates maintained a 79.6 percent market share of load obligations under RPM, down from 80.1 percent on June 1, 2008.

- **Market Concentration.** For the 2009/2010, 2010/2011, 2011/2012, and 2012/2013 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2009/2010 BRA, 2009/2010 Third IA, 2010/2011 BRA, 2010/2011 Third IA, 2011/2012 BRA, and 2011/2012 First IA all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test. Six participants included in the incremental supply of EMAAC passed the test. Offer caps were applied to all sell offers that did not pass the test.

6 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

- **Imports and Exports.** Net exchange increased 1,688.3 MW from June 1, 2008 to June 1, 2009. Net exchange, which is imports less exports, increased due to an increase in imports of 45.1 MW and a decrease in exports of 1,643.2 MW.

- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market increased by 3,206.9 MW from 4,167.5 MW on June 1, 2008 to 7,374.4 MW on June 1, 2009. Prior to the 2012/2013 delivery year, demand-side resources included DR cleared in the RPM Auctions and certified/forecast interruptible load for reliability (ILR). For delivery years 2012/2013 and beyond, ILR was eliminated and demand-side resources include DR and EE resources.

- **Net Excess.** Net excess increased 3,254.4 MW from 5,011.1 MW on June 1, 2008 to 8,265.5 MW on June 1, 2009.

Market Conduct

- **2009/2010 RPM Base Residual Auction.** Of the 1,093 generating resources which submitted offers, unit-specific offer caps were calculated for 151 resources (13.8 percent). Offer caps of all kinds were calculated for 550 resources (50.3 percent), of which 377 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2009/2010 Third Incremental Auction.** Of the 267 generating resources which submitted offers, 255 resources chose the offer cap option of 1.1 times the BRA clearing price (95.5 percent).[7] Unit-specific offer caps were calculated for two resources (0.7 percent). Offer caps of all kinds were calculated for five resources (1.9 percent), of which one was based on the technology specific default (proxy) ACR calculated by the MMU.

- **2010/2011 RPM Base Residual Auction.** Of the 1,104 generating resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2010/2011 Third Incremental Auction.** Of the 303 generating resources which submitted offers, 193 resources chose the offer cap option of 1.1 times the BRA clearing price (63.7 percent). Unit-specific offer caps were calculated for one resource (0.3 percent). Offer caps of all kinds were calculated for nine resources (2.9 percent), of which seven were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2011/2012 RPM Base Residual Auction.** Of the 1,125 generating resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 303 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2011/2012 RPM First Incremental Auction.** Of the 129 generating resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.7 percent). Offer caps of all kinds were calculated for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2012/2013 RPM Base Residual Auction.**[8] Of the 1,133 generating resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). Offer caps of all kinds were calculated for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR calculated by the MMU.

Market Performance

2009/2010 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 157,318.2 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2009/2010 RPM Base Residual Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. After accounting for FRR committed resources and imports, RPM capacity was 136,300.4 MW. The 132,231.8 MW of cleared resources for the entire RTO represented a reserve margin of 17.8 percent, which was 1,784.0 MW greater than the reliability requirement of 130,447.8 MW (installed reserve margin (IRM) of 15.0 percent) and resulted in a clearing price of $102.04 per MW-day.

  Total cleared resources in the RTO were 132,231.8 MW which resulted in a net excess of 8,265.5 MW, an increase of 3,254.4 MW from the net excess of 5,011.1 MW in the 2008/2009 RPM BRA. Certified interruptible load for reliability (ILR) was 6,481.5 MW.

7 124 FERC ¶ 61,140 (2008).

8 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, see "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>

Cleared resources across the entire RTO will receive a total of $7.5 billion based on the unforced MW cleared and the prices in the 2009/2010 RPM BRA, an increase of approximately $1.4 billion from the 2008/2009 planning year.

- **MAAC+APS.**[9] Total internal MAAC+APS unforced capacity of 73,012.9 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. Including imports into MAAC+APS, RPM unforced capacity was 73,102.2 MW.[10] Of the 5,764.9 MW of incremental supply, 5,314.7 MW cleared, which resulted in a resource-clearing price of $191.32 per MW-day.

  Total resources in MAAC+APS were 77,488.7 MW, which when combined with certified ILR of 3,081.0 MW resulted in a net excess of 2,666.8 MW (3.4 percent) greater than the reliability requirement of 77,902.9 MW.

- **SWMAAC.** Total internal SWMAAC unforced capacity of 10,345.2 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. There were no imports from outside PJM into SWMAAC. Of the 2,413.7 MW of incremental supply, 2,016.6 cleared, which resulted in a resource-clearing price of $237.33 per MW-day.

  Total resources in SWMAAC were 16,305.6 MW, which when combined with certified ILR of 519.3 MW resulted in a net excess of 506.1 MW (3.1 percent) greater than the reliability requirement of 16,318.8 MW.

2009/2010 RPM Third Incremental Auction

- **RTO.** There were 3,255.8 MW offered into the Third Incremental Auction while buy bids totaled 2,697.6 MW. Cleared volumes in the RTO were 1,798.4 MW, resulting in an RTO clearing price of $40.00 per MW-day. The 1,457.4 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared resources across the entire RTO will receive a total of $47.7 million based on the unforced MW cleared and the prices in the 2009/2010 RPM Third Incremental Auction.

- **MAAC+APS.** In MAAC+APS, 2,142.3 MW were offered into the auction while buy bids in MAAC+APS totaled 1,953.2 MW. Cleared volumes in MAAC+APS were 1,275.3 MW, resulting in a MAAC+APS clearing price of $86.00 per MW-day. The 867.0 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

- **SWMAAC.** Although SWMAAC was a constrained LDA in the 2009/2010 BRA, supply and demand curves resulted in a price less than the MAAC+APS clearing price. Supply offers in the incremental auction in SWMAAC (985.1 MW) exceeded SWMAAC demand bids (135.5 MW). The result was that all of SWMAAC supply which cleared received the MAAC+APS clearing price.

Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 7.5 percent in 2009 to 6.7 percent in the first three months of 2010. PJM EFORp decreased from 4.0 percent in 2009 to 3.7 percent in the first three months of 2010.[11]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor increased from 85.7 percent in 2009 to 87.6 percent in the first three months of 2010.

- **Outages Deemed Outside Management Control (OMC).** According to NERC criteria, an outage may be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

9 MAAC was an acronym for Mid-Atlantic Area Council, EMAAC was an acronym for Eastern Mid-Atlantic Area Council, and SWMAAC was an acronym for Southwestern Mid-Atlantic Area Council. MAAC no longer exists as its role was taken on by Reliabilty*First* Corporation. MAAC, EMAAC and SWMAAC are now regions of PJM.

10 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 6 (Effective June 18, 2009), p. 31, <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.25 MB). The import MW into MAAC+APS consist of MW under a grandfathered agreement related to Rural Electric Cooperatives (RECs) generation.

11 2009 data is for the 12 months ended December 31, 2009, as downloaded from the PJM GADS database on February 23, 2010. 2010 data is for the period ending March 31, 2010, as downloaded from the PJM GADS database on April 21, 2010. Annual EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market during the first three months of 2010. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive during the first three months of 2010.

RPM Capacity Market

Market Structure

Supply

Table 5-1 Internal capacity: June 1, 2008, to June 1, 2012[12] (See 2009 SOM, Table 5-1)

	UCAP (MW)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
Total internal capacity @ 01-Jun-08	156,968.0	72,889.5			10,777.1		
New generation	439.2	109.9			0.0		
Units out of retirement	0.0	0.0			0.0		
Generation capmods	74.1	(149.7)			(298.2)		
DR mods	220.6	163.2			42.3		
Net EFORd effect	(383.7)	0.0			(176.0)		
Total internal capacity @ 01-Jun-09	157,318.2	73,012.9			10,345.2	1,587.0	
New generation	406.9					0.0	
Units out of retirement	165.0					0.0	
Generation capmods	1,085.8					(85.5)	
DR mods	43.7					15.7	
Net EFORd effect	11.3					28.9	
Total internal capacity @ 01-Jun-10	159,030.9					1,546.1	
New generation	2,203.7						
Units out of retirement	486.9						
Generation capmods	(2,567.6)						
DR mods	684.4						
Net EFORd effect	44.4						
Total internal capacity @ 01-Jun-11	159,882.7		66,329.7	32,733.0		1,460.3	4,167.5
Reclassification of Duquesne resources	3,187.2		0.0	0.0		0.0	0.0
Adjusted internal capacity @ 01-Jun-11	163,069.9		66,329.7	32,733.0		1,460.3	4,167.5
New generation	661.3		61.9	59.7		0.0	0.0
Units out of retirement	0.0		0.0	0.0		0.0	0.0
Generation capmods	(1,513.1)		(901.3)	(444.9)		(31.8)	(509.0)
DR mods	8,028.7		3,829.7	1,480.9		64.6	67.6
EE mods	652.5		186.9	24.4		0.0	0.9
Net EFORd effect	(946.0)		(503.0)	(185.6)		5.8	18.3
Total internal capacity @ 01-Jun-12	169,953.3		69,003.9	33,667.5		1,498.9	3,745.3

12 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS and MAAC include EMAAC and SWMAAC. EMAAC includes DPL South and PSEG North. Results for only constrained LDAs are shown. Maps of the LDAs can be found in the *2009 State of the Market Report for PJM*, Appendix A, "PJM Geography."

Demand

Table 5-2 PJM Capacity Market load obligation served: June 1, 2009 (See 2009 SOM, Table 5-2)

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	68,587.1	11,994.4	26,027.0	1,056.0	10,452.7	517.3	15,252.5	133,887.0
Percent of total obligation	51.2%	9.0%	19.4%	0.8%	7.8%	0.4%	11.4%	100.0%

Market Concentration

Preliminary Market Structure Screen

Table 5-3 Preliminary market structure screen results: 2009/2010 through 2013/2014 RPM Auctions (See 2009 SOM, Table 5-3)

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2009/2010				
RTO	18.4%	853	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail
2010/2011				
RTO	18.4%	853	1	Fail
EMAAC	31.3%	2053	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail
2011/2012				
RTO	18.0%	855	1	Fail
2012/2013				
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail
2013/2014				
RTO	14.4%	812	1	Fail
MAAC	18.1%	1101	1	Fail
EMAAC	33.0%	1992	1	Fail
SWMAAC	50.9%	4790	1	Fail
PSEG	89.7%	8069	1	Fail
PSEG North	89.5%	8056	1	Fail
DPL South	55.8%	3887	1	Fail
JCPL	28.5%	1731	1	Fail
Pepco	94.5%	8947	1	Fail

Auction Market Structure

Table 5-4 RSI results: 2009/2010 through 2012/2013 RPM Auctions[13] (See 2009 SOM, Table 5-4)

RPM Markets	RSI[3]	Total Participants	Failed RSI[3] Participants
2009/2010 BRA			
RTO	0.60	66	66
MAAC+APS	0.37	21	21
SWMAAC	0.00	3	3
2009/2010 Third IA			
RTO	0.64	40	40
MAAC+APS	0.14	8	8
2010/2011 BRA			
RTO	0.60	68	68
DPL South	0.00	2	2
2010/2011 Third IA			
RTO	0.53	47	47
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First IA			
RTO	0.62	30	30
2012/2013 BRA			
RTO	0.63	98	98
MAAC/SWMAAC	0.54	15	15
EMAAC/PSEG	7.03	6	0
PSEG North	0.00	2	2
DPL South	0.00	3	3

13 The RSI shown is the lowest RSI in the market.

Imports and Exports

Table 5-5 PJM capacity summary (MW): June 1, 2007, to June 1, 2012[14] (See 2009 SOM, Table 5-5)

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4
RPM net excess	5,240.5	5,011.1	8,265.5	1,149.2	3,156.6	5,754.4
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2
EE cleared						568.9
ILR	1,636.3	3,608.1	6,481.5	2,110.5	1,593.8	
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1
Short-Term Resource Procurement Target						3,343.3

14 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2008/2009 and 2009/2010, certified ILR was used in the calculation. For 2010/2011, forecast ILR less FRR DR is used in the calculation because PJM forecast ILR including FRR DR for the first four base residual auctions. FRR DR is not subtracted in the calculation for the 2011/2012 auction, because PJM forecast ILR excluding FRR DR for the 2011/2012 BRA. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

Demand-Side Resources

Table 5-6 RPM load management statistics: June 1, 2008 to June 1, 2012[15] (See 2009 SOM, Table 5-6)

	UCAP (MW)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
DR cleared	559.4			169.0	309.2		
ILR certified	3,608.1			622.6	219.7		
RPM load management @ 01-June-2008	4,167.5			791.6	528.9		
DR cleared	892.9	813.9			356.3		
ILR certified	6,481.5	1,055.7			345.7		
RPM load management @ 01-June-2009	7,374.4	1,869.6			702.0		
DR cleared	962.9					14.9	
ILR forecast - FRR DR	1,657.6					22.2	
RPM load management @ 01-June-2010	2,620.5					37.1	
DR cleared	1,364.9						
ILR forecast	1,593.8						
RPM load management @ 01-June-2011	2,958.7						
DR cleared	7,047.2		4,723.7	1,638.4		64.6	67.6
EE cleared	568.9		179.9	20.0		0.0	0.9
RPM load management @ 01-June-2012	7,616.1		4,903.6			64.6	68.5

15 PJM used forecast ILR, including FRR DR, for the first four base residual auctions. For 2008/2009 and 2009/2010, certified ILR data were used in the calculation here because the certified ILR data are now available. For 2010/2011, forecast ILR less FRR DR is used and will continue to be used until certified ILR data are available. PJM used forecast ILR, excluding FRR DR, for the 2011/2012 BRA. Therefore, FRR DR is not subtracted in the calculation here for the 2011/2012 auction. Effective the 2012/2013 delivery year, ILR was eliminated and the Energy Efficiency (EE) resource type was eligible to be offered in RPM auctions.

Market Conduct

Offer Caps

Table 5-7 ACR statistics: 2009/2010 RPM Auctions (See 2009 SOM, Table 5-7)

	2009/2010 BRA		2009/2010 Third IA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	377	34.5%	1	0.4%
ACR data input (non-APIR)	22	2.0%	0	0.0%
ACR data input (APIR)	129	11.8%	2	0.7%
Opportunity cost input	10	0.9%	2	0.7%
Transition adder only	12	1.1%	0	0.0%
Offer caps calculated	550	50.3%	5	1.9%
Uncapped new units	3	0.3%	6	2.2%
Generators capped at 1.1 times BRA clearing price	NA		255	95.5%
Generator price takers	540	49.4%	1	0.4%
Generating units offered	1,093	100.0%	267	100.0%
Demand resources offered	38		13	
Total capacity resources offered	1,131		280	

Table 5-8 ACR statistics: 2010/2011 through 2012/2013 RPM Auctions (See 2009 SOM, Table 5-8)

	2010/2011 BRA		2010/2011 Third IA		2011/2012 BRA		2011/2012 First IA		2012/2013 BRA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	370	33.5%	7	2.3%	301	26.8%	47	36.4%	476	42.0%
ACR data input (non-APIR)	20	1.8%	0	0.0%	12	1.1%	18	14.0%	118	10.4%
ACR data input (APIR)	134	12.1%	1	0.3%	133	11.8%	1	0.8%	2	0.2%
Opportunity cost input	8	0.7%	1	0.3%	24	2.1%	2	1.6%	8	0.7%
Default ACR and opportunity cost input	0	0.0%	0	0.0%	2	0.2%	0	0.0%	3	0.3%
Offer caps calculated	532	48.1%	9	2.9%	472	42.0%	68	52.8%	607	53.6%
Uncapped new units	15	1.4%	0	0.0%	20	1.8%	1	0.8%	11	1.0%
Generators capped at 1.1 times BRA clearing price	NA		193	63.7%	NA		NA		NA	
Generator price takers	557	50.5%	101	33.4%	633	56.2%	60	46.4%	515	45.4%
Generating units offered	1,104	100.0%	303	100.0%	1,125	100.0%	129	100.0%	1,133	100.0%
Demand resources offered	23		34		37		0		233	
Energy efficiency resources offered	0		0		0		0		53	
Total capacity resources offered	1,127		337		1,162		129		1,419	

Table 5-9 APIR statistics: 2009/2010 through 2012/2013 RPM Auctions[16,17,18] (See 2009 SOM, Table 5-9)

		Weighted-Average ($ per MW-day UCAP)						
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Opportunity Costs	Total
2008/2009 BRA								
Non-APIR units	ACR	$38.81	$24.59	$70.24	$151.50	$76.66		$86.25
	Net revenues	$61.58	$21.17	$25.62	$362.48	$496.75		$184.49
	Offer caps	$17.14	$13.33	$45.63	$9.14	$4.30	$106.44	$20.45
APIR units	ACR	$40.64	$18.08	$121.39	$297.81	$27.61		$129.96
	Net revenues	$99.11	$19.60	$20.19	$202.87	$15.76		$89.95
	Offer caps	$4.70	$4.60	$101.20	$109.96	$21.85		$58.46
	APIR	$0.80	$4.92	$28.47	$131.38	$15.54		$49.29
	Maximum APIR effect							$211.28
2008/2009 Third IA								
Non-APIR units	ACR	$25.17	$24.46	$75.38	$155.14	$23.56		$68.29
	Net revenues	$40.23	$16.75	$31.25	$307.06	$53.07		$105.35
	Offer caps	$12.08	$14.75	$46.66	$24.31	$8.86	$149.90	$39.73
APIR units	ACR	$112.16	$11.96	$781.65	$348.73	NA		$350.53
	Net revenues	$256.98	$18.33	$1.53	$141.61	NA		$140.94
	Offer caps	$0.00	$1.29	$780.12	$207.12	NA		$209.74
	APIR	$0.56	$2.61	$199.31	$126.64	NA		$126.82
	Maximum APIR effect							$209.26
2009/2010 BRA								
Non-APIR units	ACR	$37.74	$26.07	$80.09	$159.26	$84.07		$82.66
	Net revenues	$61.97	$23.08	$31.92	$321.88	$516.72		$162.48
	Offer caps	$14.76	$13.51	$49.81	$11.44	$1.36	$123.60	$26.32
APIR units	ACR	$58.12	$43.83	$129.59	$525.98	$30.71		$285.17
	Net revenues	$97.94	$16.10	$19.71	$322.91	$15.75		$172.57
	Offer caps	$17.93	$30.45	$109.88	$164.31	$22.45		$102.07
	APIR	$0.24	$22.86	$43.79	$386.13	$18.96		$195.85
	Maximum APIR effect							$383.79
2010/2011 BRA								
Non-APIR units	ACR	$34.39	$27.10	$67.57	$167.08	$82.55		$80.86
	Net revenues	$96.75	$18.81	$15.19	$302.79	$391.00		$151.31
	Offer caps	$10.13	$14.12	$52.38	$9.67	$4.53	$124.60	$20.98
APIR units	ACR	$61.61	$49.26	$152.09	$654.18	$34.62		$360.27
	Net revenues	$26.84	$10.32	$20.94	$525.48	$2.07		$263.27
	Offer caps	$37.30	$39.41	$131.15	$155.39	$32.55		$110.25
	APIR	$9.87	$30.93	$60.54	$521.16	$22.42		$272.18
	Maximum APIR effect							$577.03

16 The weighted-average offer cap can still be positive even when the weighted-average net revenues are higher than the weighted-average ACR due to the offer-cap minimum being zero. On a unit basis, if net revenues are greater than ACR, net revenues in an amount equal to the ACR are used in the calculation and the offer cap is zero.
17 This table has been updated since the MMU RPM Auction reports were posted. The 2010/2011 and 2011/2012 BRA values for Oil and Gas Steam and Sub Critical/Super Critical Coal for resources with an APIR component were updated due to a prior misclassification.
18 Statistics for the 2009/2010 Third IA and the 2010/2011 Third IA are not included as the majority the resources chose the offer cap option of 1.1 times the BRA clearing price.

Table 5-9 APIR statistics: 2009/2010 through 2012/2013 RPM Auctions (See 2009 SOM, Table 5-9) continued

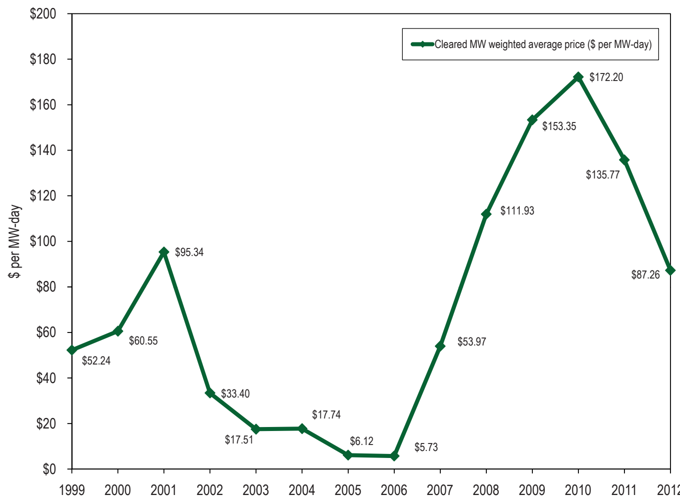
(continued)		Weighted-Average ($ per MW-day UCAP)						
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Opportunity Costs	Total
Non-APIR units	ACR	$39.52	$30.17	$72.20	$181.52	$62.54		$75.86
	Net revenues	$69.04	$20.16	$17.27	$466.41	$322.78		$173.54
	Offer caps	$11.76	$16.42	$62.13	$7.88	$11.50	$182.41	$45.80
APIR units	ACR	$61.66	$56.28	$184.34	$723.65	$36.03		$424.49
	Net revenues	$78.17	$10.35	$19.81	$531.93	$2.06		$286.80
	Offer caps	$34.69	$46.18	$164.54	$203.41	$33.97		$147.77
	APIR	$11.82	$37.28	$91.30	$578.47	$24.68		$324.58
	Maximum APIR effect							$523.26
2011/2012 First IA								
Non-APIR units	ACR	$54.15	$29.43	$71.79	$284.63	$30.04		$169.77
	Net revenues	$220.31	$44.98	$10.25	$298.96	$0.07		$195.83
	Offer caps	$2.66	$2.64	$61.54	$150.63	$29.97	$136.01	$78.56
APIR units	ACR	$220.20	$152.28	$194.25	$583.59	NA		$326.57
	Net revenues	$81.72	$6.94	$23.64	$328.71	NA		$128.90
	Offer caps	$138.48	$145.34	$170.62	$254.88	NA		$197.67
	APIR	$220.19	$120.84	$82.87	$324.31	NA		$170.61
	Maximum APIR effect							$468.26
2012/2013 BRA								
Non-APIR units	ACR	$41.84	$32.61	$75.47	$207.54	$57.18		$110.84
	Net revenues	$91.67	$35.29	$7.51	$396.82	$257.96		$208.65
	Offer caps	$5.28	$14.40	$67.96	$11.31	$15.63	$136.48	$21.55
APIR units	ACR	$218.10	$49.83	$177.52	$715.10	NA		$464.65
	Net revenues	$98.97	$15.62	$3.62	$508.00	NA		$302.04
	Offer caps	$119.12	$34.96	$173.89	$215.38	NA		$167.62
	APIR	$218.10	$26.59	$89.08	$559.97	NA		$351.74
	Maximum APIR effect							$1,155.57

Market Performance

Table 5-10 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions (See 2009 SOM, Table 5-10)

	RPM Clearing Price ($ per MW-day)						
	RTO	MAAC+ APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
2007/2008 BRA	$40.80			$197.67	$188.54		
2008/2009 BRA	$111.92			$148.80	$210.11		
2008/2009 Third IA	$10.00				$223.85		
2009/2010 BRA	$102.04	$191.32			$237.33		
2009/2010 Third IA	$40.00	$86.00					
2010/2011 BRA	$174.29					$186.12	
2010/2011 Third IA	$50.00						
2011/2012 BRA	$110.00						
2011/2012 First IA	$55.00						
2011/2012 ATSI FRR Integration Auction	$108.89						
2012/2013 BRA	$16.46		$133.37	$139.73		$222.30	$185.00
2012/2013 ATSI FRR Integration Auction	$20.46						

Figure 5-1 History of capacity prices: Calendar year 1999 through 2012[19] (See 2009 SOM, Figure 5-1)



19 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2012 capacity prices are RPM weighted average prices.

Table 5-11 RPM cost to load: 2009/2010 through 2012/2013 RPM Auctions[20,21,22] (See 2009 SOM, Table 5-11)

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2009/2010 BRA			
RTO	$104.82	56,696.9	$2,169,117,837
MAAC+APS	$193.78	60,984.3	$4,313,445,473
SWMAAC	$224.86	16,205.7	$1,330,043,812
2010/2011 BRA			
RTO	$183.05	129,340.6	$8,641,666,369
DPL	$187.24	4,507.5	$308,053,731
2011/2012 BRA			
RTO	$110.04	133,815.3	$5,389,363,034
2012/2013 BRA			
RTO	$16.46	69,648.3	$418,440,022
MAAC	$129.63	31,338.7	$1,482,789,024
EMAAC	$135.18	21,171.5	$1,044,616,630
DPL	$162.99	4,685.6	$278,752,670
PSEG	$149.65	12,642.7	$690,572,720

20 The annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
21 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.
22 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second IA. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third IA. Effective with the 2012/2013 delivery year, the Final UCAP Obligation is determined after the clearing of the final incremental auction. Prior to the 2012/2013 delivery year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 delivery year, the Final Zonal Capacity Prices are determined after the final incremental auction. The 2010/2011 Net Load Prices are not finalized. The 2011/2012 and 2012/2013 Net Load Prices and Obligation MW are not finalized.

2009/2010 RPM Base Residual Auction

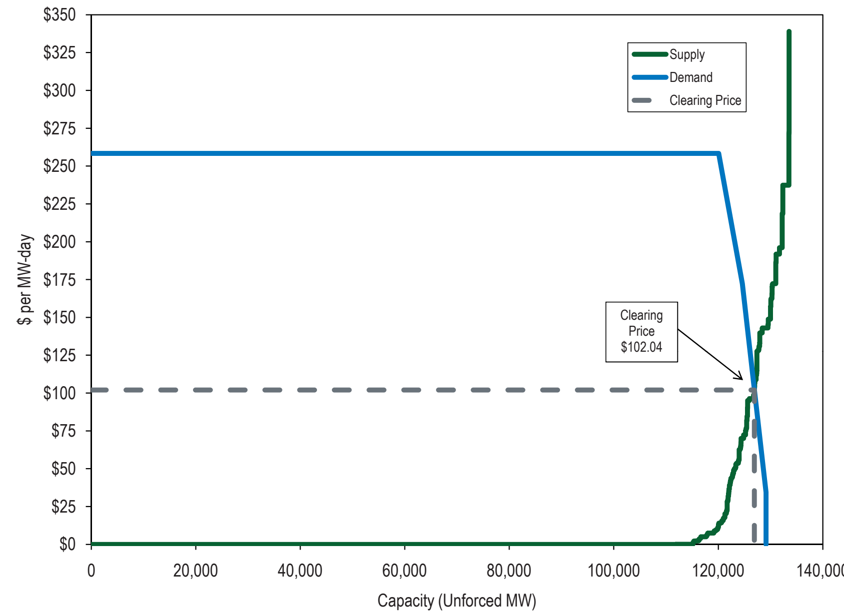
RTO

Table 5-12 RTO offer statistics: 2009/2010 RPM Base Residual Auction[23] (See 2009 SOM, Table 5-12)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal RTO Capacity (Gen and DR)	166,639.7	157,318.2		
FRR	(25,316.2)	(23,523.2)		
Imports	2,652.5	2,505.4		
RPM Capacity	143,976.0	136,300.4		
Exports	(2,376.2)	(2,194.9)		
FRR Optional	(552.5)	(450.2)		
Excused	(136.8)	(104.3)		
Available	140,910.5	133,551.0	100.0%	100.0%
Generation Offered	140,003.6	132,614.2	99.4%	99.3%
DR Offered	906.9	936.8	0.6%	0.7%
Total Offered	140,910.5	133,551.0	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	133,859.0	126,917.1	95.0%	95.0%
Cleared in LDAs	5,594.4	5,314.7	4.0%	4.0%
Total Cleared	139,453.4	132,231.8	99.0%	99.0%
Uncleared in RTO	895.5	869.0	0.6%	0.7%
Uncleared in LDAs	561.6	450.2	0.4%	0.3%
Total Uncleared	1,457.1	1,319.2	1.0%	1.0%
Reliability Requirement		130,447.8		
Total Cleared		132,231.8		
ILR Certified		6,481.5		
RPM Net Excess/(Deficit)		8,265.5		
Resource Clearing Price ($ per MW-day)		$102.04	A	
Final Zonal Capacity Price ($ per MW-day)		$104.82	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$0.00	C	
Final Zonal ILR Price ($ per MW-day)		$102.04	A-C	
Net Load Price ($ per MW-day)		$104.82	B-C	

23 Prices are only for those generating units outside of MAAC+APS and SWMAAC.

Figure 5-2 RTO market supply/demand curves: 2009/2010 RPM Base Residual Auction[24] (See 2009 SOM, Figure 5-2)



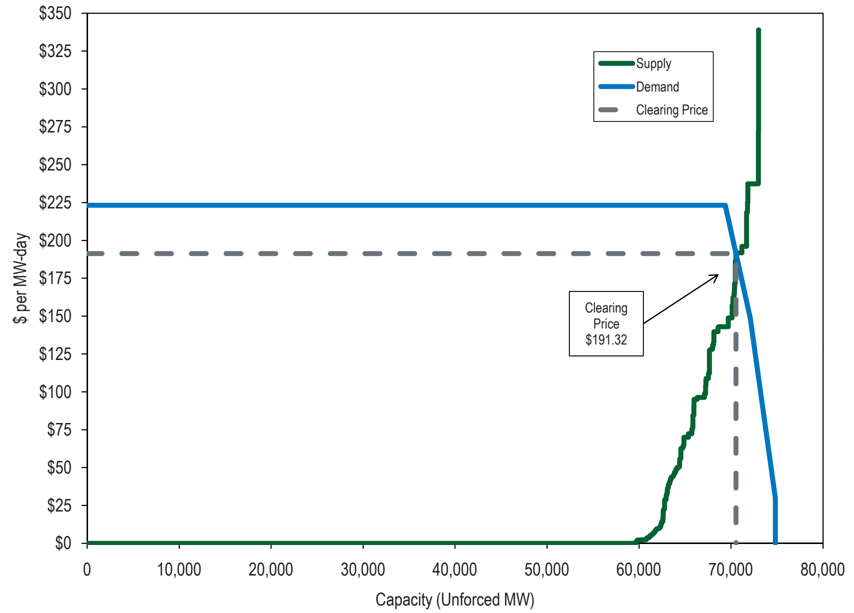
24 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in MAAC+APS and SWMAAC.

MAAC+APS

Table 5-13 MAAC+APS offer statistics: 2009/2010 RPM Base Residual Auction (See 2009 SOM, Table 5-13)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal MAAC+APS Capacity (Gen and DR)	77,870.6	73,012.9		
Imports	89.3	89.3		
RPM Capacity	77,959.9	73,102.2		
Exports	0.0	0.0		
Excused	(136.8)	(104.3)		
Available	77,823.1	72,997.9	100.0%	100.0%
Generation Offered	77,028.6	72,177.3	99.0%	98.9%
DR Offered	794.5	820.6	1.0%	1.1%
Total Offered	77,823.1	72,997.9	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	71,667.1	67,233.0	92.1%	92.1%
Cleared in LDAs	5,594.4	5,314.7	7.2%	7.3%
Total Cleared	77,261.5	72,547.7	99.3%	99.4%
Uncleared	561.6	450.2	0.7%	0.6%
Reliability Requirement		77,902.9		
Total Cleared		72,547.7		
CETL		4,941.0		
Total Resources		77,488.7		
ILR Certified		3,081.0		
RPM Net Excess/(Deficit)		2,666.8		
Resource Clearing Price ($ per MW-day)		$191.32	A	
Final Zonal Capacity Price ($ per MW-day)		$196.54	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$2.77	C	
Final Zonal ILR Price ($ per MW-day)		$188.55	A-C	
Net Load Price ($ per MW-day)		$193.77	B-C	

Figure 5-3 MAAC+APS supply/demand curves: 2009/2010 RPM Base Residual Auction[25] (See 2009 SOM, Figure 5-3)



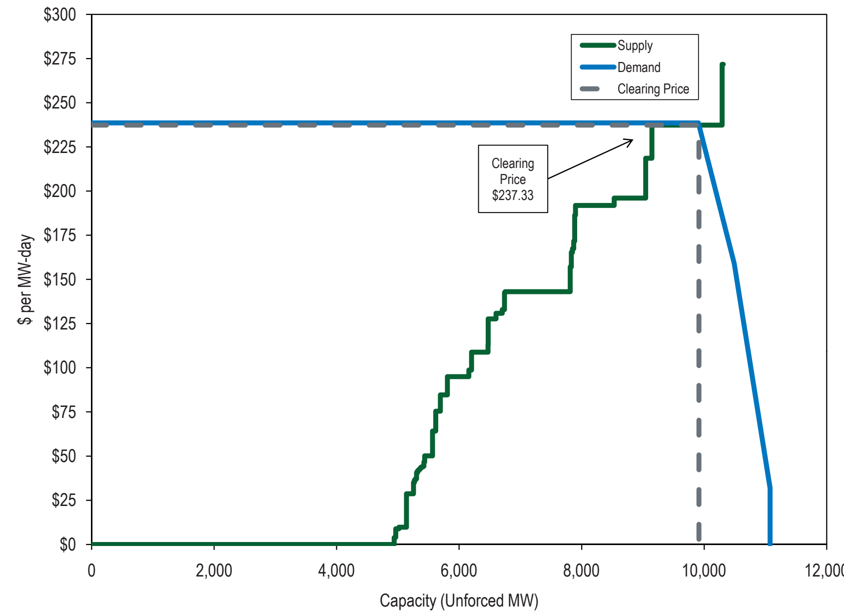
25 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in SWMAAC.

SWMAAC

Table 5-14 SWMAAC offer statistics: 2009/2010 RPM Base Residual Auction (See 2009 SOM, Table 5-14)

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal SWMAAC Capacity (Gen and DR)	11,448.6	10,345.2		
Imports	0.0	0.0		
RPM Capacity	11,448.6	10,345.2		
Exports	0.0	0.0		
Excused	(37.0)	(33.5)		
Available	11,411.6	10,311.7	100.0%	100.0%
Generation Offered	11,066.7	9,955.4	97.0%	96.5%
DR Offered	344.9	356.3	3.0%	3.5%
Total Offered	11,411.6	10,311.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	7,001.2	6,202.3	61.4%	60.1%
Cleared in MAAC+APS	1,784.3	1,695.7	15.6%	16.4%
Cleared in LDA	2,146.2	2,016.6	18.8%	19.6%
Total Cleared	10,931.7	9,914.6	95.8%	96.1%
Uncleared	479.9	397.1	4.2%	3.9%
Reliability Requirement		16,318.8		
Total Cleared		9,914.6		
CETL		6,391.0		
Total Resources		16,305.6		
ILR Certified		519.3		
RPM Net Excess/(Deficit)		506.1		
Resource Clearing Price ($ per MW-day)		$237.33	A	
Final Zonal Capacity Price ($ per MW-day)		$243.80	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$19.21	C	
Final Zonal ILR Price ($ per MW-day)		$218.12	A-C	
Final Net Load Price ($ per MW-day)		$224.59	B-C	

Figure 5-4 SWMAAC supply/demand curves: 2009/2010 RPM Base Residual Auction (See 2009 SOM, Figure 5-4)



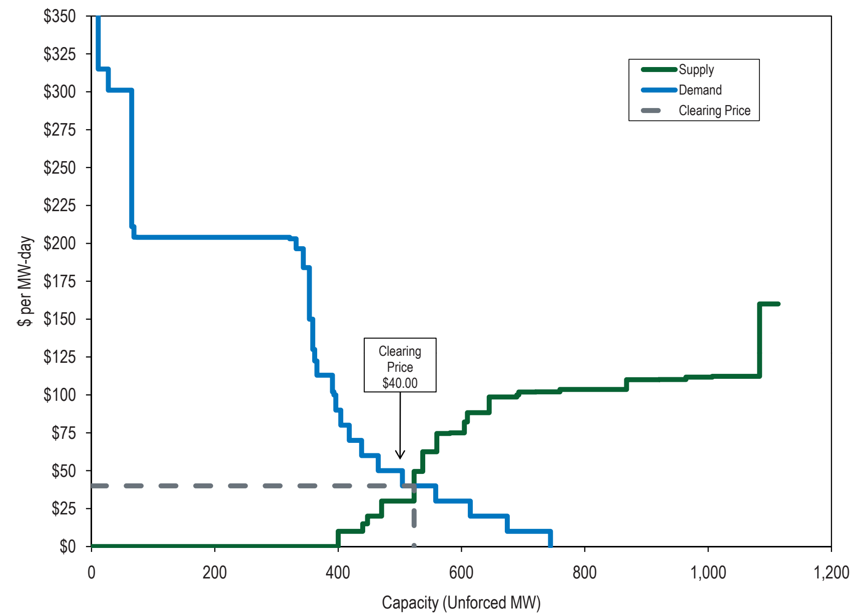
2009/2010 RPM Third Incremental Auction

RTO

Table 5-15 RTO offer statistics: 2009/2010 RPM Third Incremental Auction (See 2009 SOM, Table 5-15)

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,918.7	2,724.4	
DR	514.6	531.4	
Total	3,433.3	3,255.8	2,697.6
Cleared in RTO	539.9	523.1	523.1
Cleared in MAAC+APS	1,364.1	1,275.3	1,275.3
Total cleared	1,904.0	1,798.4	1,798.4
Uncleared in RTO	589.6	590.4	221.3
Uncleared in MAAC+APS	939.7	867.0	677.9
Total uncleared	1,529.3	1,457.4	899.2
Resource clearing price ($ per MW-day)	$40.00		

Figure 5-5 RTO supply/demand curves: 2009/2010 RPM Third Incremental Auction[26,27] (See 2009 SOM, Figure 5-5)



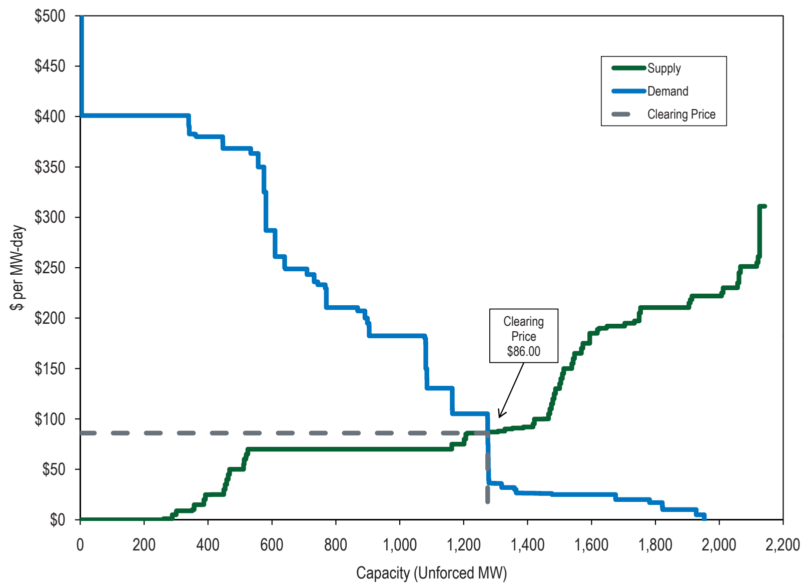
26 The supply curve includes all supply offers at the lower of offer price or offer cap.
27 For ease of viewing, the graph was truncated at $350 per MW-day and does not show a buy bid of approximately $1,000 per MW-day.

MAAC+APS

Table 5-16 MAAC+APS offer statistics: 2009/2010 RPM Third Incremental Auction (See 2009 SOM, Table 5-16)

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,043.3	1,873.3	
DR	260.5	269.0	
Total	2,303.8	2,142.3	1,953.2
Cleared in RTO	487.3	462.9	
Cleared in MAAC+APS	876.8	812.4	
Total cleared	1,364.1	1,275.3	1,275.3
Uncleared	939.7	867.0	677.9
Resource clearing price ($ per MW-day)	$86.00		

Figure 5-6 MAAC+APS supply/demand curves: 2009/2010 RPM Third Incremental Auction[28] (See 2009 SOM, Figure 5-6)

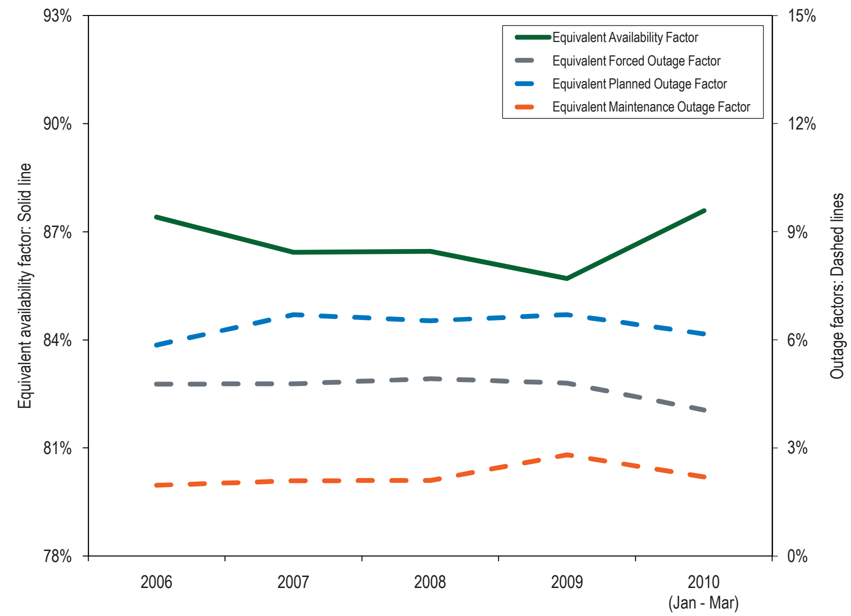


28 The supply curve includes all supply offers at the lower of offer price or offer cap.

Generator Performance

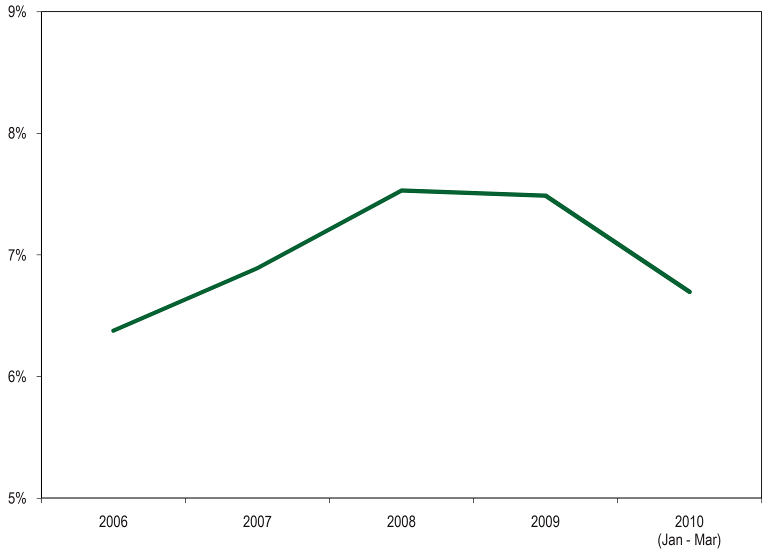
Generator Performance Factors

Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2006 to 2010 (January through March) (See 2009 SOM, Figure 5-7)



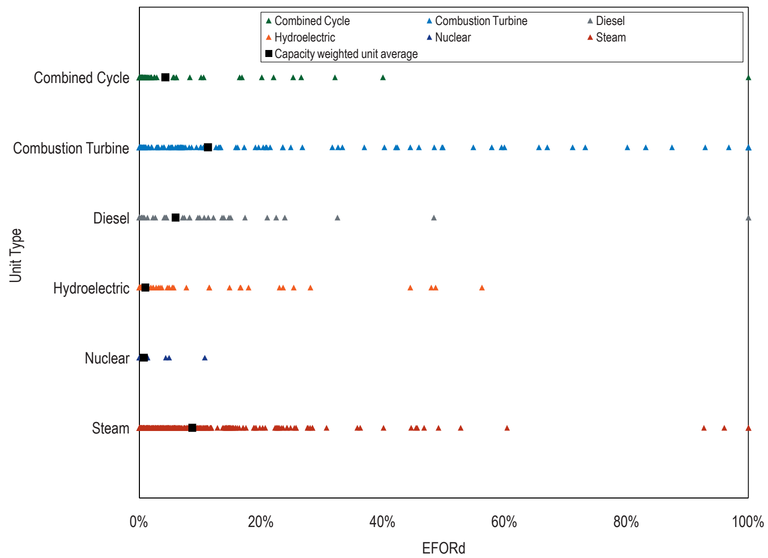
Generator Forced Outage Rates

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2006 to 2010 (January through March) (See 2009 SOM, Figure 5-8)



Distribution of EFORd

Figure 5-9 PJM 2010 (January through March) Distribution of EFORd data by unit type (See 2009 SOM, Figure 5-9)



Components of EFORd

Table 5-17 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2006 to 2010 (January through March) (See 2009 SOM, Table 5-17)

	2006	2007	2008	2009	2010 (Jan - Mar)
Combined Cycle	4.2%	3.4%	3.4%	3.8%	4.2%
Combustion Turbine	9.3%	11.0%	11.0%	9.8%	11.3%
Diesel	13.1%	12.0%	11.4%	10.2%	5.9%
Hydroelectric	1.9%	2.1%	2.0%	3.2%	1.0%
Nuclear	1.4%	1.4%	1.9%	4.1%	0.7%
Steam	8.2%	9.1%	10.1%	9.3%	8.7%
Total	6.4%	6.9%	7.5%	7.5%	6.7%

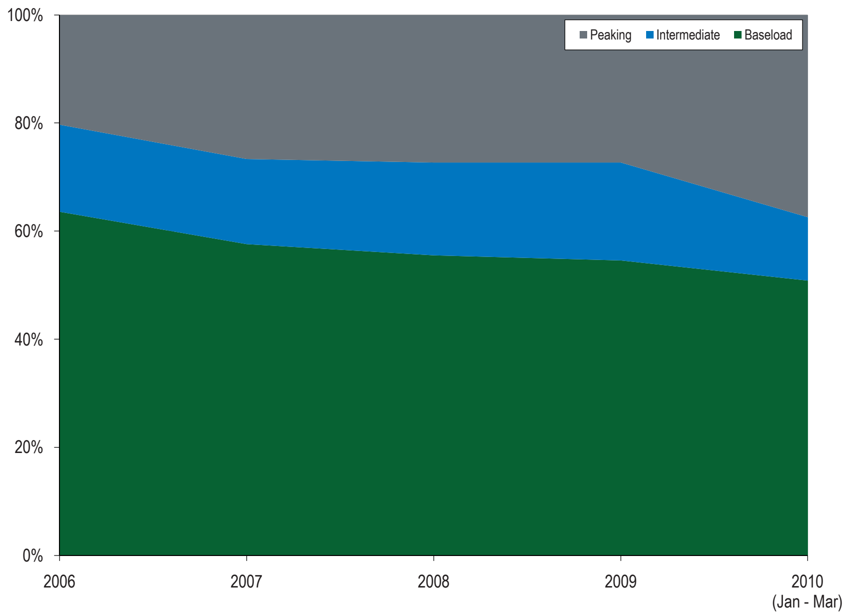
Table 5-18 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2006 to 2010 (January through March)[29] (See 2009 SOM, Table 5-18)

	2006	2007	2008	2009	2010 (Jan - Mar)	Change in 2010 from 2009
Combined Cycle	0.5	0.5	0.5	0.5	0.5	0.0
Combustion Turbine	1.4	1.7	1.7	1.5	1.7	0.2
Diesel	0.0	0.0	0.0	0.0	0.0	(0.0)
Hydroelectric	0.1	0.1	0.1	0.1	0.0	(0.1)
Nuclear	0.3	0.3	0.4	0.8	0.1	(0.6)
Steam	4.0	4.4	5.0	4.6	4.2	(0.3)
Total	6.4	6.9	7.5	7.5	6.7	(0.8)

29 Calculated values presented in Section 5, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

Duty Cycle and EFORd

Figure 5-10 Contribution to EFORd by duty cycle: Calendar years 2006 to 2010 (January through March) (See 2009 SOM, Figure 5-10)



Forced Outage Analysis

Table 5-19 Outage cause contribution to PJM EFOF: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-19)

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler Tube Leaks	1.10	22.9%
Economic	0.80	16.6%
Boiler Air and Gas Systems	0.30	6.3%
Electrical	0.28	5.8%
Fuel Quality	0.21	4.3%
Boiler Fuel Supply from Bunkers to Boiler	0.17	3.6%
Exciter	0.13	2.7%
Boiler Tube Fireside Slagging or Fouling	0.12	2.5%
Generator	0.12	2.5%
Stack Emission	0.12	2.4%
Feedwater System	0.11	2.3%
Inlet Air System and Compressors	0.09	1.8%
Cooling System	0.08	1.6%
Boiler Piping System	0.08	1.6%
Low Pressure Turbine	0.07	1.5%
Circulating Water Systems	0.07	1.4%
Controls	0.06	1.2%
Fuel, Ignition and Combustion Systems	0.06	1.1%
Precipitators	0.05	1.1%
All Other Causes	0.80	16.7%
Total	4.80	100.0%

Table 5-20 Contributions to Economic Outages: 2010 (January through March) (See 2009 SOM, Table 5-20)

	Contribution to Economic Reasons
Lack of Fuel (OMC)	74.2%
Other Economic Problems	18.7%
Lack of Fuel (Non-OMC)	6.9%
Fuel Conservation	0.3%
Lack of Water (Hydro)	0.0%
Total	100.0%

Table 5-21 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-21)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	0.8%	0.0%	0.0%	0.0%	0.0%	28.2%	22.9%
Low Pressure Turbine	0.0%	0.0%	0.0%	0.0%	17.3%	1.2%	1.5%
Economic	1.9%	35.1%	0.4%	0.2%	0.0%	16.4%	16.6%
Electrical	0.8%	26.9%	0.4%	17.8%	44.5%	2.3%	5.8%
Boiler Air and Gas Systems	0.1%	0.0%	0.0%	0.0%	0.0%	7.8%	6.3%
Generator	32.2%	0.2%	0.3%	0.1%	0.0%	0.6%	2.5%
Boiler Fuel Supply from Bunkers to Boiler	0.1%	0.0%	0.0%	0.0%	0.0%	4.4%	3.6%
Fuel Quality	0.6%	0.0%	3.1%	0.0%	0.0%	5.2%	4.3%
Stack Emission	0.0%	0.0%	0.0%	0.0%	0.0%	3.0%	2.4%
Boiler Piping System	0.3%	0.0%	0.0%	0.0%	0.0%	1.9%	1.6%
Controls	0.2%	0.8%	0.3%	9.9%	0.0%	1.3%	1.2%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.6%
Feedwater System	1.0%	0.0%	0.0%	0.0%	12.3%	2.3%	2.3%
Performance	0.9%	0.8%	0.0%	1.2%	0.0%	0.6%	0.6%
Condensing System	0.1%	0.0%	0.0%	0.0%	0.4%	1.3%	1.0%
Inlet Air System and Compressors	20.6%	6.4%	0.0%	0.0%	0.0%	0.0%	1.8%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%	2.5%
Valve	1.8%	0.0%	0.0%	0.0%	0.0%	1.2%	1.1%
Miscellaneous (Generator)	2.1%	3.2%	0.3%	11.3%	0.0%	0.6%	0.9%
All Other Causes	36.5%	26.6%	95.3%	59.5%	25.4%	17.8%	20.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-22 Contribution to EFOF by unit type: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-22)

	EFOF	Contribution to EFOF
Combined Cycle	2.0%	6.1%
Combustion Turbine	2.3%	8.9%
Diesel	3.8%	0.2%
Hydroelectric	0.7%	0.7%
Nuclear	0.7%	2.9%
Steam	6.7%	81.2%
Total	4.0%	100.0%

Outages Deemed Outside Management Control

Table 5-23 PJM EFORd vs. XEFORd: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-23)

	2010 EFORd	2010 XEFORd	Difference
Combined Cycle	4.2%	4.2%	0.0%
Combustion Turbine	11.3%	7.6%	3.7%
Diesel	5.9%	3.8%	2.2%
Hydroelectric	1.0%	0.6%	0.3%
Nuclear	0.7%	0.7%	0.0%
Steam	8.7%	7.2%	1.5%
Total	6.7%	5.4%	1.3%

Components of EFORp

Table 5-24 Contribution to EFORp by unit type (Percentage points): Calendar years 2009 to 2010 (January through March) (See 2009 SOM, Table 5-24)

	2009	2010 (Jan - Mar)
Combined Cycle	0.4	0.2
Combustion Turbine	0.4	0.4
Diesel	0.0	0.0
Hydroelectric	0.1	0.0
Nuclear	0.8	0.2
Steam	2.3	2.9
Total	4.0	3.7

Table 5-25 PJM EFORp data by unit type: Calendar years 2009 to 2010 (January through March) (See 2009 SOM, Table 5-25)

	2009	2010 (Jan - Mar)
Combined Cycle	2.9%	1.9%
Combustion Turbine	2.5%	2.4%
Diesel	5.3%	3.7%
Hydroelectric	2.9%	0.5%
Nuclear	4.3%	1.0%
Steam	4.7%	6.0%
Total	4.0%	3.7%

EFORd, XEFORd and EFORp

Table 5-26 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-26)

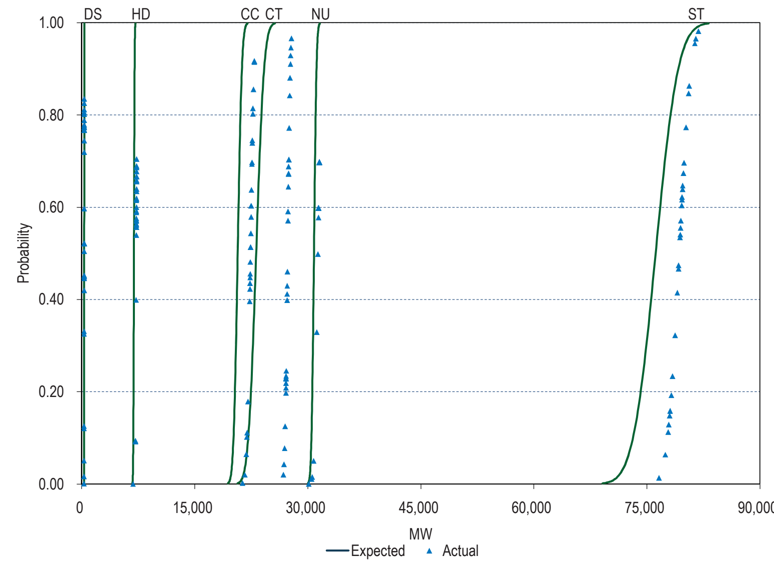
	EFORd	XEFORd	EFORp
Combined Cycle	0.5	0.5	0.2
Combustion Turbine	1.7	1.2	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.0	0.0	0.0
Nuclear	0.1	0.1	0.2
Steam	4.2	3.5	2.9
Total	6.7	5.4	3.7

Table 5-27 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-27)

	EFORd	XEFORd	EFORp
Combined Cycle	4.2%	4.2%	1.9%
Combustion Turbine	11.3%	7.6%	2.4%
Diesel	5.9%	3.8%	3.7%
Hydroelectric	1.0%	0.6%	0.5%
Nuclear	0.7%	0.7%	1.0%
Steam	8.7%	7.2%	6.0%
Total	6.7%	5.4%	3.7%

Comparison of Expected and Actual Performance

Figure 5-11 PJM 2010 (January through March) distribution of EFORd data by unit type (See 2009 SOM, Figure 5-11)



Performance During Peak Months

Figure 5-12 PJM peak month data: 2010 (See 2009 SOM, Figure 5-12)

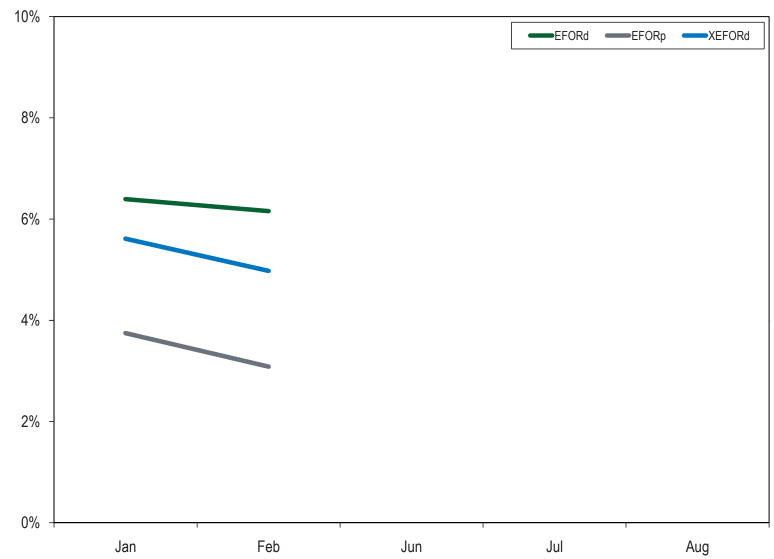
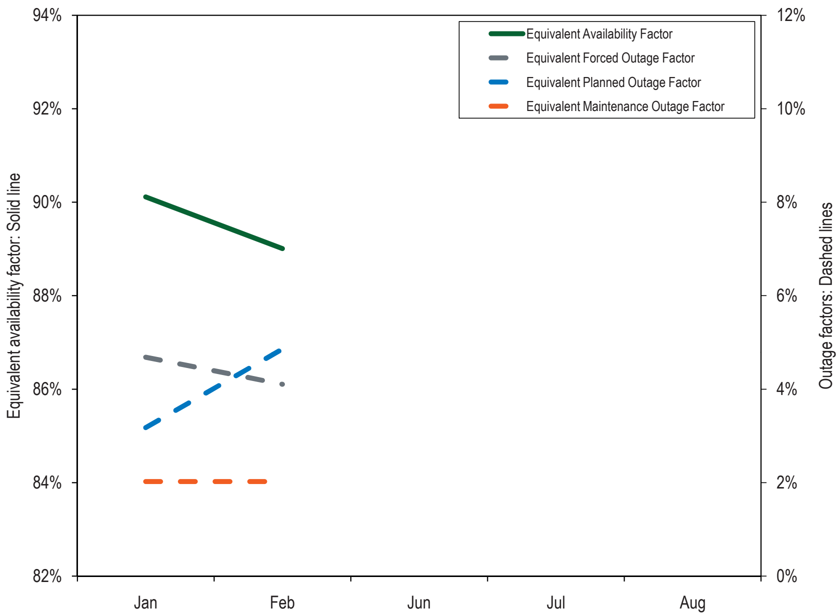


Figure 5-13 PJM peak month generator performance factors: 2010 (See 2009 SOM, Figure 5-13)



SECTION 6 - ANCILLARY SERVICE MARKETS

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[1] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on a cost basis.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

1 75 FERC ¶ 61,080 (1996).

2 Regulation is used to help control the area control error (ACE). See *2009 State of the Market Report for PJM,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in the first three months of 2010.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[3] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve Markets, and the PJM DASR Market for the first three months of 2010.

Overview

Regulation Market

The PJM Regulation Market in 2010 continues to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented four changes to the Regulation Market: introducing the Three Pivotal Supplier test for market power; increasing the margin for cost-based regulation offers; modifying the calculation of lost opportunity cost (LOC); and terminating the offset of regulation revenues against operating reserve credits. At the FERC's direction, the MMU prepared and submitted a report on November 30, 2009, on the impact of these changes.[4] The findings of the report have been updated and corrected and the results are presented below. The changes to the Regulation Market rules resulted in a significant (35 percent) increase in payments to the providers of regulation compared to what they

3 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

4 The MMU report filed in Docket No. ER09-13-000 is posted at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf>(465 KB).

would have otherwise received and compared to what they would have received in a competitive market design for the first three months of 2010.

Market Structure

- **Supply.** During the first three months of 2010, the supply of offered and eligible regulation in PJM was generally both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in the first three months of 2010. The ratio of eligible regulation offered to regulation required averaged 2.94 throughout the first three months of 2010, a decrease from the 2009 ratio of 2.98.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. Previously the requirement had been fixed daily at 1.0 percent of the daily forecast operating load. The average hourly regulation demand for the first three months of 2010 was 896 MW, compared to 898 MW for the first three months of 2009.

- **Market Concentration.** During the first three months of 2010, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1442 which is classified as "moderately concentrated."[5] The minimum hourly HHI was 921 and the maximum hourly HHI was 2983. The largest hourly market share in any single hour was 51 percent, and 87 percent of all hours had a maximum market share greater than 20 percent. For the first three months of 2010, 76 percent of hours had one or more pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market for the first three months of 2010 was characterized by structural market power in 76 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Beginning December 1, 2008, owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. All offers remain subject to the $100 per MWh cap.[6] In computing the market solution, PJM adds opportunity cost. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the regulation market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. All units of owners who fail the three pivotal supplier test for an hour have their offers capped at the lesser of their cost based or price based offer. The regulation market is then re-solved.

  As part of the changes to the regulation market implemented on December 1, 2008, cost based offers may include a margin of $12.00 rather than the prior maximum margin of $7.50. The impact of this change was to increase cost based offer prices.

  As part of the changes to the regulation market implemented on December 1, 2008, PJM calculates opportunity costs using LMP forecasts and the lesser of the available price based offer or the most expensive available cost based offer as the reference, rather than the offer on which the unit is operating.[7] PJM adds this opportunity cost to the offers of the market participants. The impact of this change was to increase cost based and price based offer prices.

Market Performance

- **Price.** For the PJM Regulation Market during the first three months of 2010, the load weighted, average price per MWh (the regulation market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $17.82. This was a decrease of $4.22, or 18 percent, from the average price for regulation during the first three months of 2009.

- **Price and Opportunity Cost.** Prices in the PJM Regulation Market during the first three months of 2010 were approximately 25 percent higher than they would have been but for the change to the definition of opportunity cost.

5 See the *2009 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

6 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p.39.

7 See PJM. "Manual 11: Scheduling Operations," Revision 44 (January 1, 2010), p. 43: "SPREGO utilizes the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the "lost opportunity cost energy schedule"), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation. "

Synchronized Reserve Market

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

PJM made two significant changes to the Synchronized Reserve Market in 2009. These changes were intended to ensure that the synchronized reserve requirement accurately reflects the needs of PJM dispatch. This includes ensuring that the forecast amount of Tier 1 synchronized reserve is actually available to PJM dispatch during the operating hour. PJM changed the primary constraint which defines the Mid-Atlantic Subzone within the RFC Synchronized Reserve Market from Bedington—Black Oak to AP South. PJM reduced from 70 percent to 15 percent the percentage of Tier 1 available west of the AP South interface that it will consider as available to the Mid-Atlantic Subzone when it calculates the amount of Tier 2 required. These changes were made to address the fact that PJM Dispatch needed more synchronized reserve than was defined as the requirement to be met by the market. This problem has existed in the Synchronized Reserve Market since late 2007. These changes reduced the amount of additional, out of market, synchronized reserve required by PJM dispatch, which reduced opportunity cost payments and aligned the total cost of synchronized reserves more closely with Synchronized Reserve Market prices. Synchronized reserves added out of market were two percent of all synchronized reserves during January through March of 2010, while they were 55 percent for the same time period in 2009. Opportunity cost payments accounted for 25 percent of total costs during January through March of 2010 compared to 62 percent during the same time period in 2009.

Market Structure

- **Supply.** For January through March of 2010, synchronized reserve offers were somewhat higher than the equivalent period in 2009. The offered and eligible excess supply ratio was 1.26 for the PJM Mid-Atlantic Synchronized Reserve Region.[8] For the RFC zone, the excess supply ratio was 2.33. The excess supply ratio is determined using the administratively required level of synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower than the required reserve level because there is usually a significant amount of Tier 1 synchronized reserve available. In the first three months of 2010, the contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

- **Demand.** The average synchronized reserve requirements were 1,320 MW for the RFC Synchronized Reserve Zone and 1,150 MW for the Mid-Atlantic Subzone. Market demand is less than the requirement by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared.

  Demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was normal in the first three months of 2010. In 11 percent of hours no Tier 2 synchronized reserve was needed. The average required Tier 2 (including self scheduled) was 450 MW.

  Synchronized reserves added out of market were two percent of all synchronized reserve during January through March of 2010.

  As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, only one percent of hours cleared a Tier 2 Synchronized Reserve Market in the RFC. A Tier 2 Synchronized Reserve Market has not yet been cleared for the Southern Synchronized Reserve Zone in the first three months of 2010. In the PJM Mid-Atlantic Synchronized Reserve Region, 87 percent of hours cleared a Tier 2 Synchronized Reserve Market. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 450 MW. Much of the demand is satisfied by the high level of self scheduled, averaging 226 MW, so the market had to clear an average of 224 MW.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for the first three months of 2010 was 2972 which is classified as "highly concentrated."[9] For purchased synchronized reserve (cleared plus added) the HHI was 3002. In 58 percent of hours the maximum market share was greater than 40 percent (compared to 36 percent of hours in 2009).

  In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, for the first three months of 2010, 59 percent of hours had three or

8 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

9 See the *2009 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in the first three months of 2010, are characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using LMP forecasts, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

  Demand side resources remained significant participants in the Synchronized Reserve Market in the first three months of 2010. In four percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by DSR.

Market Performance

- **Price.** The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $7.02 per MW for the first three months of 2010, a $0.44 per MW decrease from 2009.

- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit during the first three months of 2010.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[10] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[11] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** The DASR Market for the first three months of 2010 had no pivotal suppliers.

Market Conduct

- **Withholding.** Economic withholding remains a problem in the DASR Market. Continuing a pattern seen since the inception of the DASR Market, a significant number of units offered at levels effectively guaranteed not to clear. Five percent of units offered at $50 or more and four percent of units offered at $990 or more, in a market with an average clearing price of $0.05 and a maximum clearing price of $0.75.

- **DSR.** Demand side resources do participate in the DASR Market but remain insignificant.

Market Performance

- **Price.** For the first three months of 2010, the load weighted price of DASR was $0.05, including the 25 percent of hours when the market cleared at a price of $0.00.

Black Start Service

Black Start Service is necessary to help ensure the reliable restoration of the grid following a blackout. Black Start Service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[12]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM

10 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

11 PJM Manual 13, Emergency Requirements, Revision 39, (January 1, 2010); pp 11-12.

12 PJM OATT Schedule § 1.3BB, Second Revised Second Revised Sheet No. 33.01, March 1, 2007.

defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

PJM does not have a market to provide black start service, but compensates black start resource owners for all costs associated with providing this service, as defined in the tariff. For 2009, charges were about $12.3 million. For the first three months of 2010 changes were $2.3 million. There was substantial zonal variation.

As a consequence of PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs of compliance with Critical Infrastructure Protection standards, black start costs likely will increase substantially. The revised filing also provides a better match between the sellers' commitment period and the cost recovery period.

The MMU recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

Conclusion

The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market.[13]

The MMU has updated the calculations, improved the calculations and made corrections as necessary, based in part on PJM's comments. [14] This updated and improved analysis is presented below.

Together, the changes to the tariff related to the Regulation Market resulted in an increase in payments to the providers of regulation of $77 million over the 16 month period from December 2008 through March 2010, compared to what they would have received in the absence of these three changes. This represents an increase in total regulation payments of 25 percent for the 16 month period. While these results are based on estimates of how the market would have worked in the absence of the changes in market design, the calculations reflect detailed hourly data about the individual units in the Regulation Market supply curve. There is no question that the changes in market design significantly increased the payments for regulation service, regardless of any disagreements about the details of the calculation methods.

The MMU concludes, based on the analysis of the Regulation Market operating under the revised rules, that the results of the Regulation Market are not competitive. The results of the Regulation Market are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in offers greater than competitive offers and therefore in prices greater than competitive prices. The competitive price is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct and consistent approach to the calculation of the opportunity cost. The offers from market participants are not at issue, as PJM directly calculates and adds opportunity costs to the offers of participants, following the revised market rules. The Regulation Market results are the result of the market design changes and are not the result of the behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test.

The MMU recommends that the modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic.

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive.

The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU concludes that the DASR Market results were competitive in the first three months of 2010.

13 See the *2009 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets."

14 Comments of PJM Interconnection, L.L.C. to Report of Independent Market Monitor filed in ER09-13 (December 30, 2009). The Illinois Commerce Commission also filed comments on the MMU's report: Comments of the Illinois Commerce Commission filed in ER09-13 (January 6, 2010).

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

Overall, the MMU concludes that the Regulation Market results were not competitive in the first three months of 2010. The MMU concludes that the Synchronized Reserve Market results were competitive in the first three months of 2010. The MMU concludes that the DASR Market results were competitive in the first three months of 2010.

Regulation Market

Market Structure

Supply

Demand

Table 6-1 PJM Regulation Market required MW and ratio of supply to requirement: January through March 2010 (See 2009 SOM, Table 6-1)

Month	Average Required Regulation (MW)	Ratio of Supply To Requirement
Jan	948	2.94
Feb	942	3.05
Mar	800	2.84

Market Concentration

Table 6-2 PJM regulation capability, daily offer and hourly eligible: January through March 2010 (See 2009 SOM, Table 6-2)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,367	5,775	78%	2,650	36%
Off Peak	7,367			2,369	32%
On Peak	7,367			2,964	40%

Table 6-3 PJM cleared regulation HHI: January through March 2010 (See 2009 SOM, Table 6-3)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, 1st Quarter, 2010	921	1442	2983

Figure 6-1 Figure 6-1 PJM Regulation Market HHI distribution: January through March 2010 (See 2009 SOM, Figure 6-1)

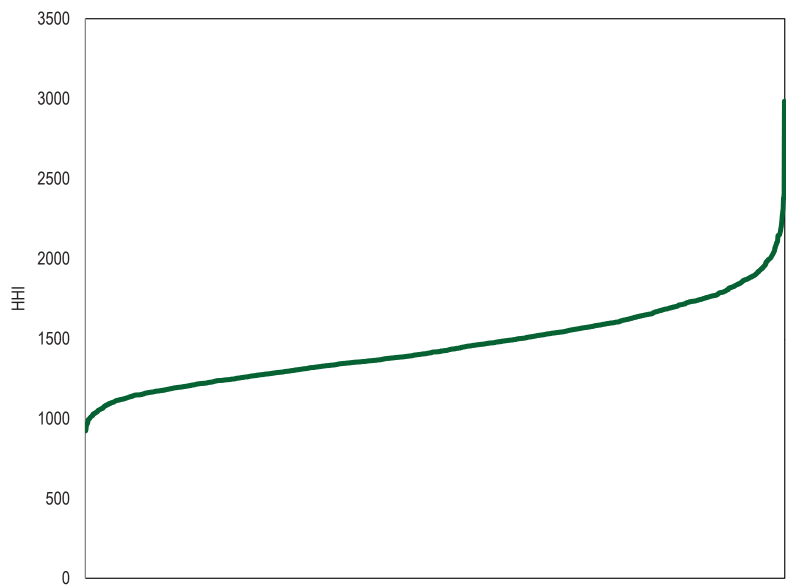


Figure 6-2 Off peak and on peak regulation levels: January through March 2010 (See 2009 SOM, Figure 6-2)

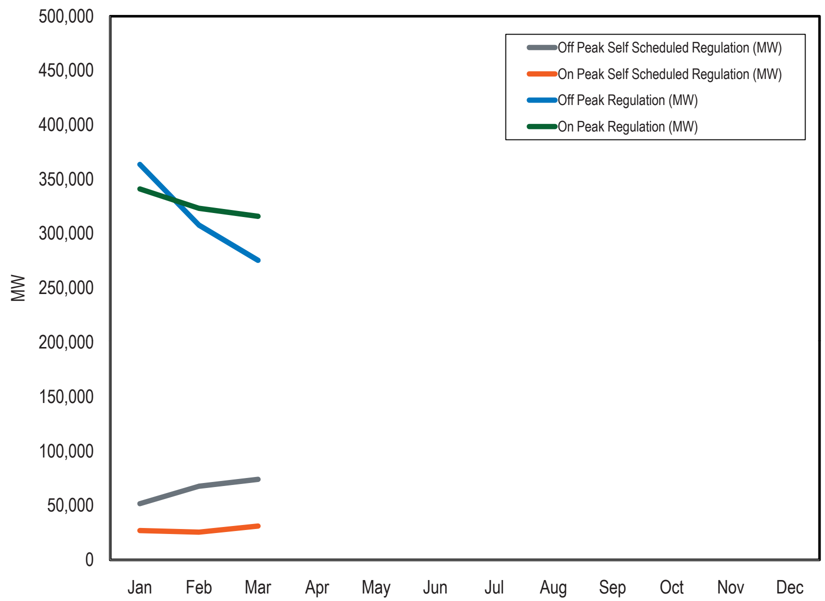


Table 6-4 Highest annual average hourly Regulation Market shares: January through March 2010 (See 2009 SOM, Table 6-4)

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	20%
2	16%
3	14%
4	13%
5	10%

Table 6-5 Regulation market monthly three pivotal supplier results: January through March 2010 (See 2009 SOM, Table 6-5)

Month	Percent of Hours With Three Pivotal Suppliers
Jan	74%
Feb	70%
Mar	83%

Market Performance

Price

Table 6-6 Percent of hours when marginal unit supplier was pivotal: January through March 2010 (See 2009 SOM, Table 6-6)

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	67%
Feb	58%
Mar	73%

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): January through March 2010 (See 2009 SOM, Figure 6-3)

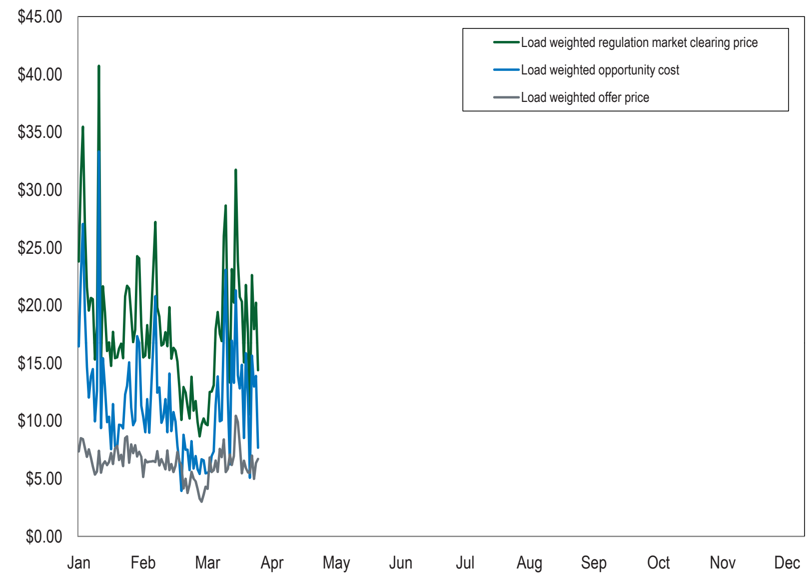


Figure 6-4 Monthly average regulation demand (required) vs. price: January through March 2010 (See 2009 SOM, Figure 6-4)

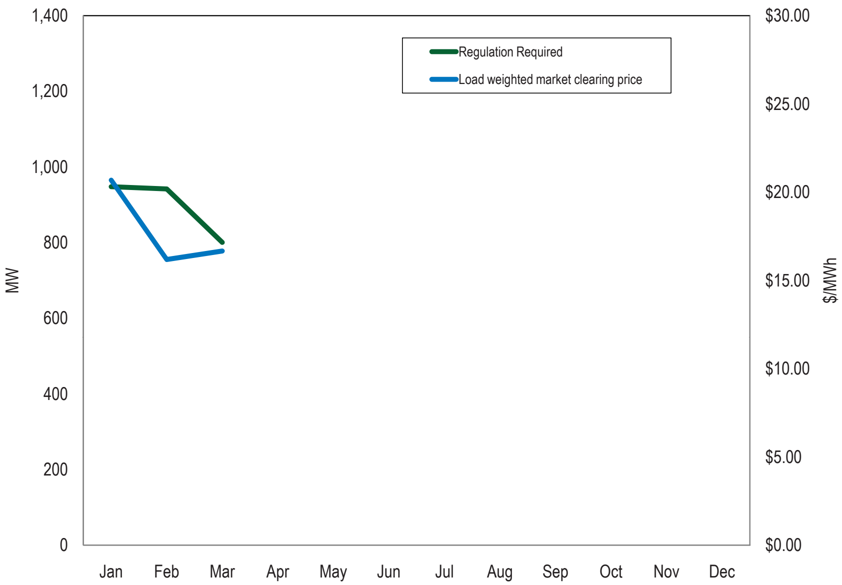


Figure 6-5 Monthly load weighted, average regulation cost and price: January through March 2010 (See 2009 SOM, Figure 6-5)

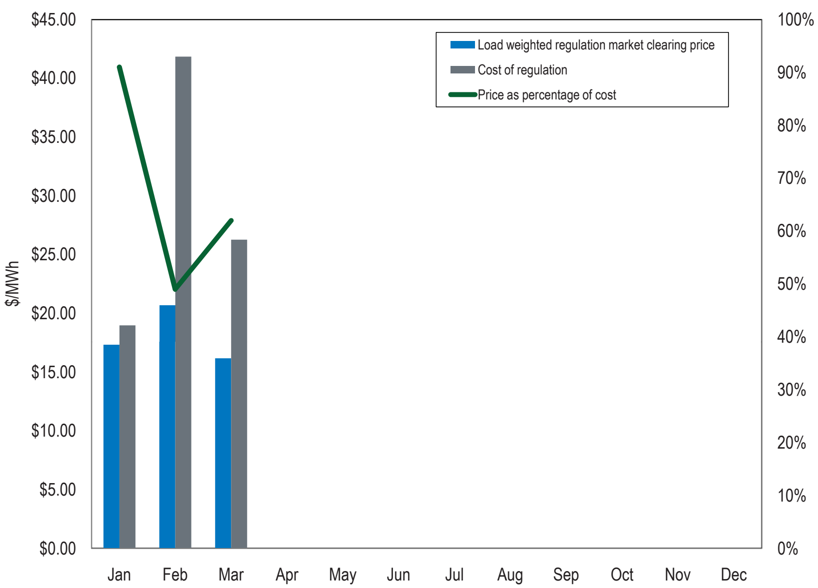


Table 6-7 Total regulation charges: January through March 2010 (See 2009 SOM, Table 6-7)

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load Weighted Regulation Market Clearing Price ($/MWh)	Cost of Regulation ($/MWh)
Jan	704,362	$29,479,645	$20.66	$41.85
Feb	632,007	$16,673,515	$16.17	$26.38
Mar	591,046	$14,058,674	$16.62	$23.79

Analysis of Regulation Market Changes

Table 6-8 Summary of changes to Regulation Market design (See 2009 SOM, Table 6-8)

Prior Regulation Market Rules (Effective May 1, 2005 through November 30, 2008)	New Regulation Market Rules (Effective December 1, 2008)
1. No structural test for market power.	1. Three Pivotal Supplier structural test for market power.
2. Offers capped at cost for identified dominant suppliers. (American Electric Power Company(AEP) and Virginia Electric Power Company (Dominion)) Price offers capped at $100 per MW.	2. Offers capped at cost for owners that fail the TPS test. Price offers capped at $100 per MW.
3. Cost based offers include a margin of $7.50 per MW.	3. Cost based offers include a margin of $12.00 per MW.
4. Opportunity cost calculated based on the offer schedule on which the unit is dispatched in the energy market.	4. Opportunity cost calculated based on the lesser of the price-based offer schedule or the highest cost-based offer schedule in the energy market.
5. All regulation net revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.	5. No regulation market revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.

Introduction of TPS Testing

Table 6-9 Regulation Market pivotal supplier test results: December 2008 through March 2010 and December 2007 through March 2009 (See 2009 SOM, Table 6-9)

Year	Month	Percent of Hours With Three Pivotal Suppliers	Year	Month	Percent of Hours With Three Pivotal Suppliers
2008	Dec	92%	2007	Dec	79%
2009	Jan	84%	2008	Jan	84%
2009	Feb	61%	2008	Feb	83%
2009	Mar	42%	2008	Mar	89%
2009	Apr	39%	2008	Apr	88%
2009	May	31%	2008	May	97%
2009	Jun	37%	2008	Jun	77%
2009	Jul	39%	2008	Jul	75%
2009	Aug	35%	2008	Aug	80%
2009	Sep	47%	2008	Sep	74%
2009	Oct	64%	2008	Oct	89%
2009	Nov	62%	2008	Nov	59%
2009	Dec	80%	2008	Dec	92%
2010	Jan	74%	2009	Jan	84%
2010	Feb	70%	2009	Feb	61%
2010	Mar	83%	2009	Mar	42%

Increase Offer Margin from $7.50 to $12.00

Table 6-10 Impact of $12 adder to cost based regulation offer: January through March 2010 (See 2009 SOM, Table 6-10)

Year	Month	Load Weighted Regulation Market Clearing Price	Load Weighted Regulation Market Clearing Price With Old Rule	Total Regulation Credits	Regulation Credits Attributable to New Rule	Percent Increase in Total Credits Due to Increase of Markup from $7.50 to $12.00
2010	Jan	$20.66	$16.91	$29,479,645	$2,641,053	9%
2010	Feb	$16.17	$13.22	$16,673,515	$1,861,195	11%
2010	Mar	$16.66	$13.63	$14,058,674	$1,438,051	11%
Total				$60,211,834	$5,940,299	9.9%

Change in the Definition of Opportunity Cost

Table 6-11 Impact to Regulation Market Clearing Price of using lesser of price based energy schedule or most expensive cost-based energy schedule: January through March 2010 (See 2009 SOM, Table 6-11)

			New Rule		Old Rule			
Year	Month	Average Regulation Required (MW)	Load Weighted RMCP Using Lesser Schedule for Opportunity Cost	Using Lesser Schedule For Opportunity Costs, Total Charges	Load Weighted RMCP Using Current Dispatch Schedule for Opportunity Costs	Using Current Dispatch Schedule for Opportunity Costs, Total Charges	Additional Regulation Credits Paid Using New Rule	Pecentage Increase in Regulation Credits
2010	Jan	950	$20.66	$29,479,645	$11.56	$23,065,981	$6,413,664	22%
2010	Feb	944	$16.17	$16,490,553	$9.93	$12,730,541	$3,760,012	23%
2010	Mar	802	$16.66	$13,780,240	$8.71	$9,205,222	$4,575,018	33%
Total				$59,750,438		$45,001,744	$14,748,694	25%

Eliminate Offset Against Balancing Operating Reserves Credits

Table 6-12 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: January through March 2010 (See 2009 SOM, Table 6-12)

Year	Month	Balancing Operating Reserves No Longer Offset	Total Regulation Credits	Percent of Regulation Credits No Longer Offsetting Operating Reserves
2010	Jan	$64,990	$29,479,645	0%
2010	Feb	$66,223	$16,673,515	0%
2010	Mar	$135,728	$14,058,674	1%

Summary

Table 6-13 Summary of additional charges paid as a result of December 1, 2008 changes to Regulation Market rules: January through March 2010, including December 2008 through December 2009 totals (See 2009 SOM, Table 6-13)

			Increasing Markup from $7.50 to $12.00		Opportunity Cost Calculated Using Lower of Price Based or Cost Based Price		Regulation Credits Above Cost Plus Opportunity Costs no Longer Offset Against Operating Reserves		Changes for Three Pivotal Supplier Testing, December 1, 2008 - Summary	
Year	Month	Total Regulation Credits	RMCP Credits Attributable to Marginal Units Cost Offer > Costs Plus $7.50	Percent Increase in Total Credits Due to Marginal Unit With Offer > Cost Plus $7.50	Additional Regulation Credits Paid Due to New Opportunity Cost Calculation	Percentage Increase in Regulation Credits Due to New Opportunity Cost Calculation	Balancing Operating Reserve Credits No Longer Offset	Percent of Regulation Credits No Longer Offsetting Operating Reserves	Total Additional Generator Credits	Total Percent of Regulation Credits Additional
2010	Jan	$29,479,645	$2,641,053	9%	$6,413,664	22%	$64,990	0%	$9,119,707	31%
2010	Feb	$16,673,515	$1,861,195	11%	$3,760,012	23%	$66,223	0%	$5,687,430	34%
2010	Mar	$14,058,674	$1,438,051	10%	$4,575,018	33%	$135,728	1%	$6,148,797	44%
Jan-Mar 2010 Total		$60,211,834	$5,940,299	9.9%	$14,748,694	24%	$266,941	0%	$20,955,934	35%
Dec 08 - Dec 09 Total		$247,893,142	$6,189,406	2.5%	$47,463,833	19%	$2,297,348	1%	$55,950,587	23%
Dec 08 - Mar 10 Total		$308,104,976	$12,129,705	3.9%	$62,212,527	20%	$2,564,289	1%	$76,906,521	25%

Synchronized Reserve Market

Market Structure

Demand

Figure 6-6 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through March 2010 (See 2009 SOM, Figure 6-6)

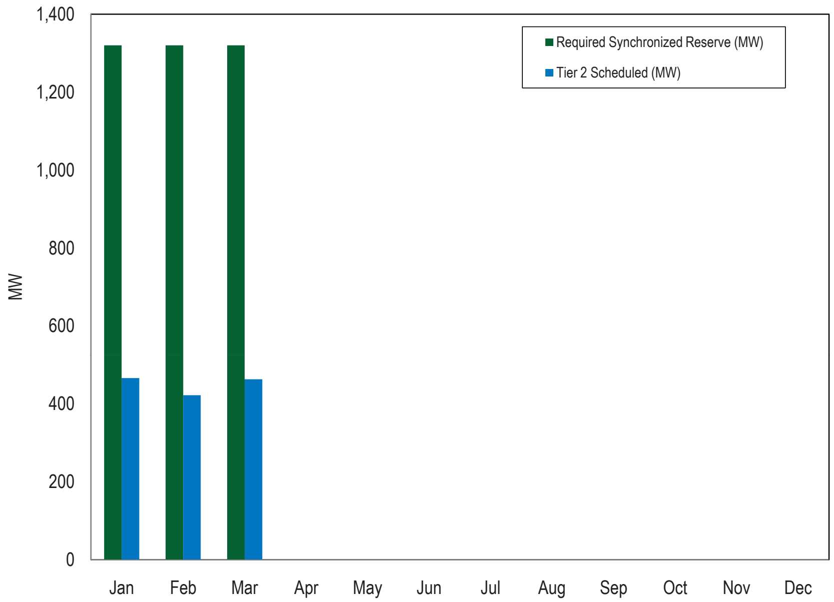
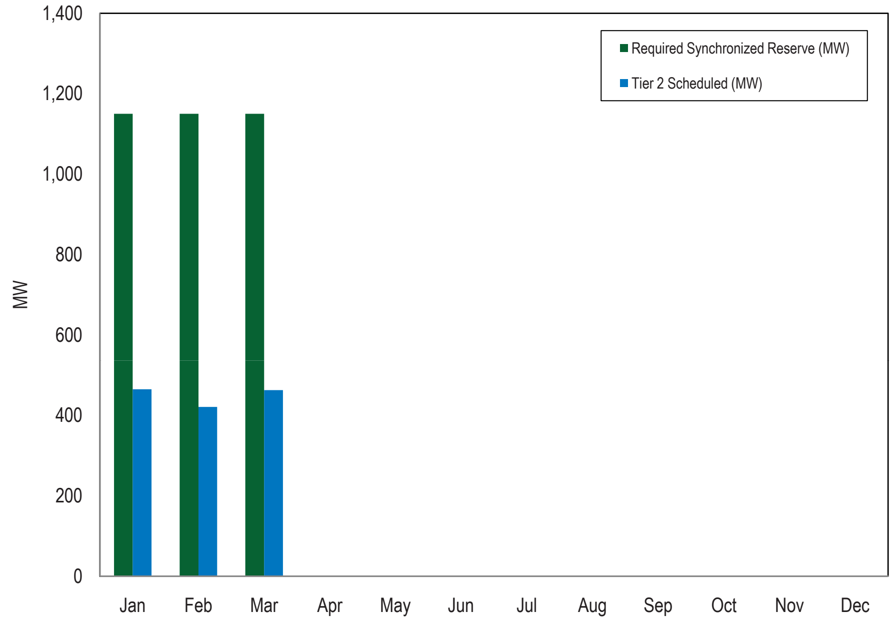


Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through March 2010 (See 2009 SOM, Figure 6-7)



Market Concentration

Figure 6-8 Purchased Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: January through March 2010 (See 2009 SOM, Figure 6-8)

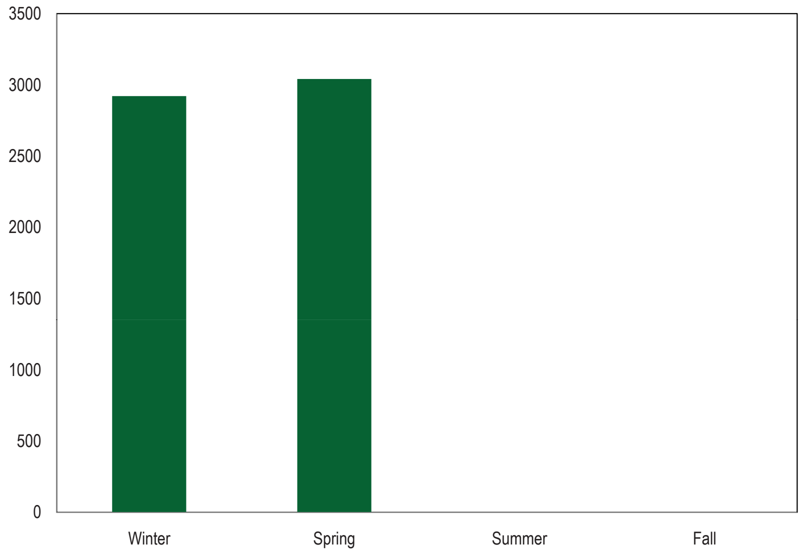


Table 6-14 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares: January through March 2010 (See 2009 SOM, Table 6-15)

Company Market Share Rank	Cleared Synchronized Reserve Top Market Shares
1	40%
2	30%
3	22%
4	16%
5	8%

Market Conduct

Offers

Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through March 2010 (See 2009 SOM, Figure 6-9)

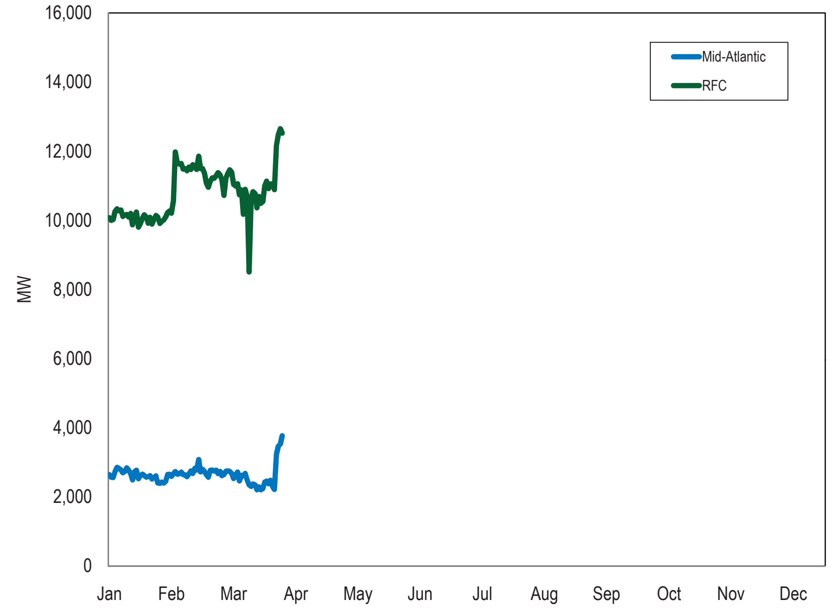


Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through March 2010 (See 2009 SOM, Figure 6-10)

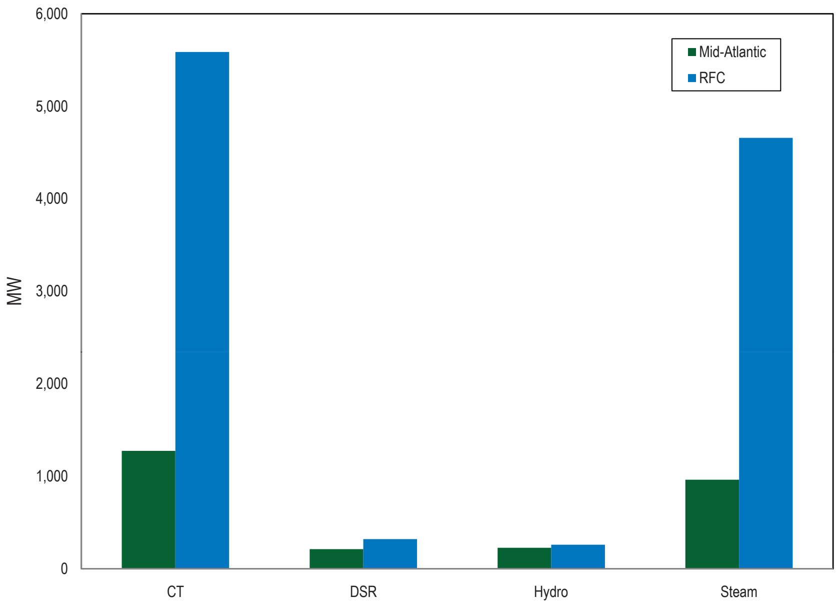
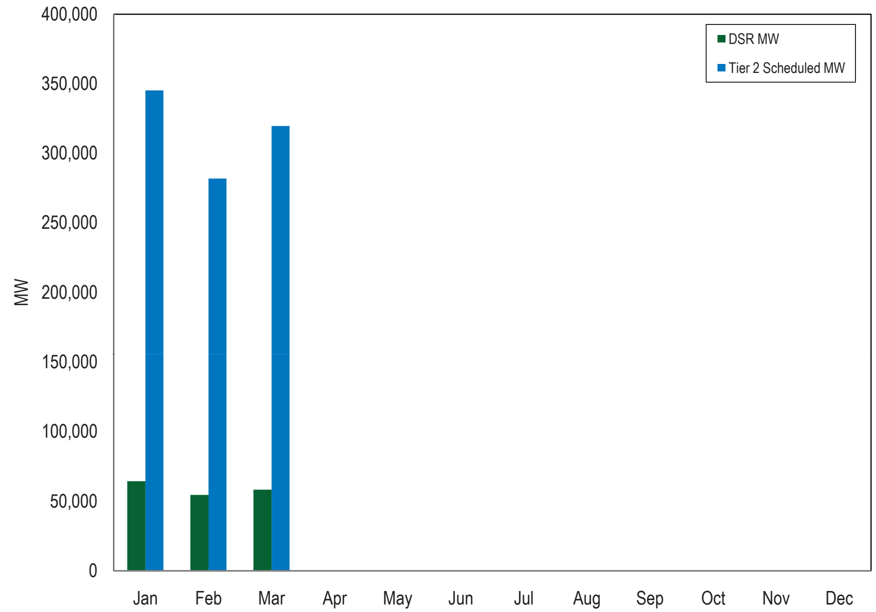


Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through March 2010 (See 2009 SOM, Figure 6-11)



DSR

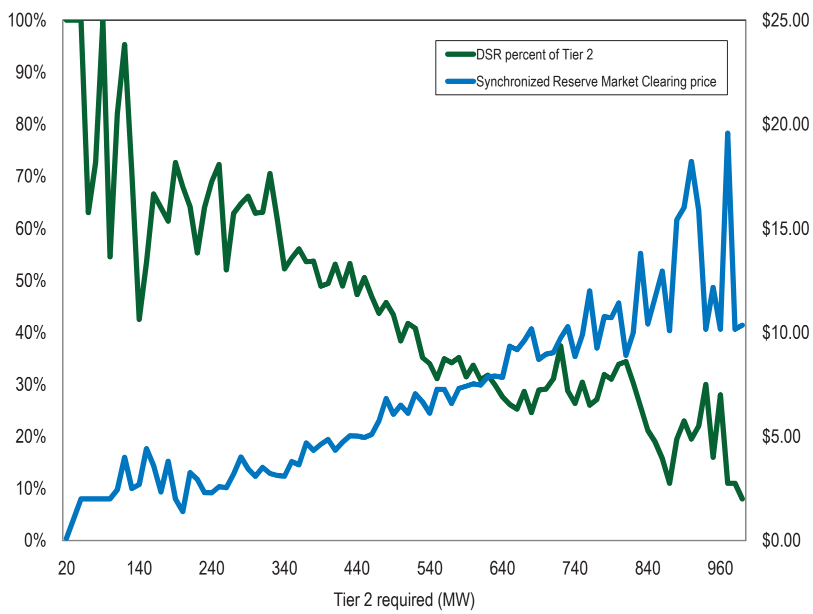
Table 6-15 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: January through March 2010 (See 2009 SOM, Table 6-16)

Month	Average SRMCP when all cleared synchronized reserve is DSR	Percent of scheduled synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$5.84	33%	$2.03	4%
Feb	$5.97	31%	$0.10	1%
Mar	$8.45	39%	$2.03	6%

Market Performance

Price

Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: January through March 2010 (See 2009 SOM, Figure 6-12)



Price and Cost

Figure 6-13 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through March 2010 (See 2009 SOM, Figure 6-13)

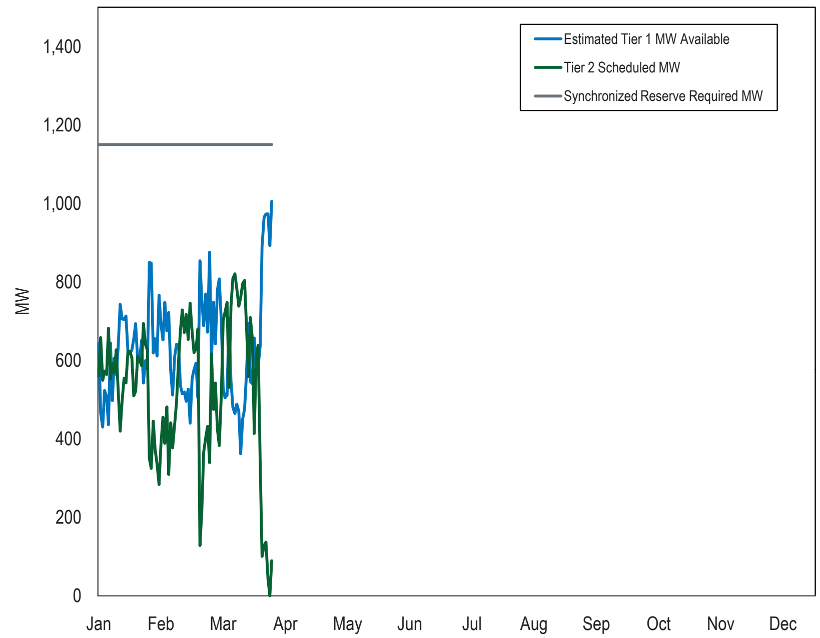


Figure 6-14 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through March 2010 (See 2009 SOM, Figure 6-14)

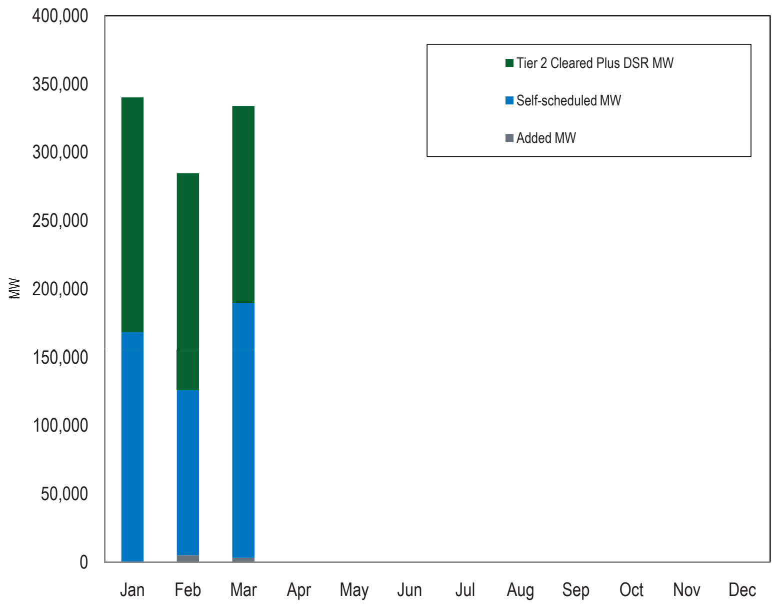


Figure 6-15 Figure 6-15 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: January through March 2010 (See 2009 SOM, Figure 6-15)

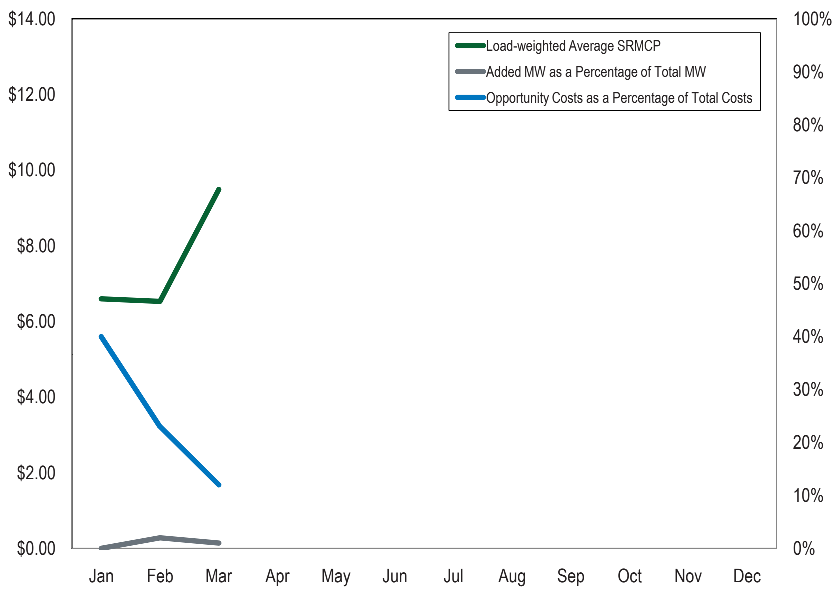
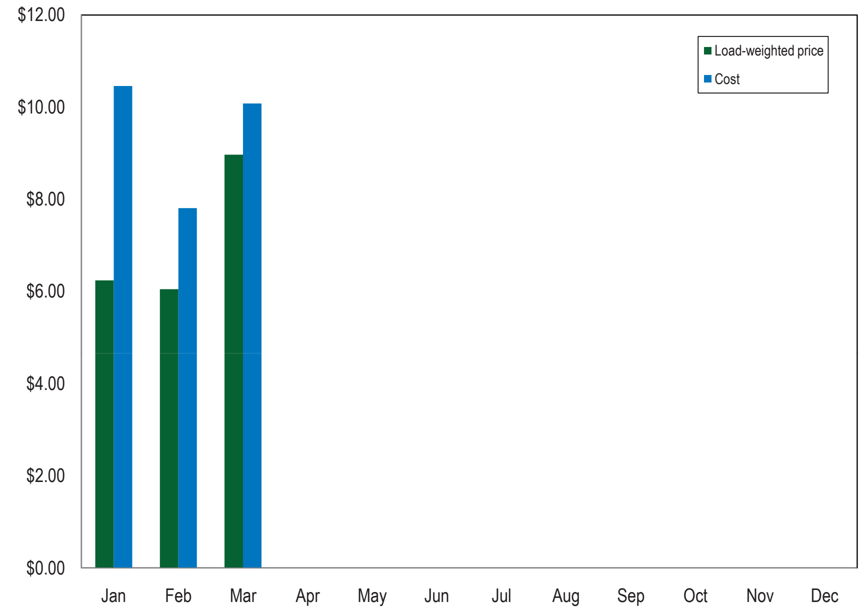


Figure 6-16 Comparison of RFC Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): January through March 2010 (See 2009 SOM, Figure 6-16)



Day Ahead Scheduling Reserve (DASR)

Table 6-16 2009 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through March 2010 (See 2009 SOM, Table 6-17)

Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Purchased	Total DASR Credits
Jan	6,246	$0.00	$0.75	$0.05	4,647,334	$242,018
Feb	6,191	$0.00	$0.50	$0.06	4,160,064	$228,087
Mar	5,441	$0.00	$0.50	$0.03	4,042,540	$109,862

Black Start Service

Table 6-17 Black Start yearly zonal charges for network transmission use: January through March 2010 (See 2009 SOM, Table 6-18)

Zone	Network Charges
AECO	$92,809
AEP	$183,837
AP	$34,005
BGE	$120,471
ComEd	$925,229
DAY	$36,547
DPL	$97,576
DLCO	$6,668
JCPL	$109,132
Met-Ed	$101,468
PECO	$181,492
PENELEC	$84,560
Pepco	$55,756
PPL	$38,706
PSEG	$236,763
UGI	$38,706

SECTION 7 – CONGESTION

Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[1] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Locational marginal prices (LMPs) reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying characteristics of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would require direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of Auction Revenue Rights (ARRs) and/or Financial Transmission Rights (FTRs). While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[2]

The Market Monitoring Unit (MMU) analyzed congestion and its influence on PJM markets during the first three months of 2010.

1 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

2 See the *2009 State of the Market Report for PJM*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $38.4 million or 13 percent, from $306.9 million in the first three months of 2009 to $345.3 million in the first three months of 2010. Day-ahead congestion costs increased by $2.58 million or one percent, from $389.5 million in the first three months of 2009 to $392.1 million in the first three months of 2010. Balancing congestion costs increased by $35.8 million or 43 percent, from -$82.6 million in the first three months of 2009 to -$46.8 million in the first three months of 2010. Total congestion costs have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were four percent of total PJM billings in the first three months of 2010. Total PJM billings in the first three months of 2010 were $8.415 billion.

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In the first three months of 2010, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in the first three months of 2010 ranged from $20.4 million in March to $218.5 million in January.

Congestion Component of LMP and Facility or Zonal Congestion

- **Congestion Component of Locational Marginal Price (LMP).** To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation between eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface. This interface had the effect of increasing prices in eastern and southern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones.

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first three months of 2010.[3] Day-ahead congestion frequency increased from 2009 to 2010 by 1,017 congestion event hours or five percent. In the first three months of 2010, there were 19,548 day-ahead, congestion-event hours compared to 18,531 day-ahead, congestion-event hours in the first three months of 2009. Day-ahead, congestion-event hours increased on internal PJM interfaces and the reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) while congestion frequency on PJM lines and transformers decreased. Real-time congestion frequency decreased from 2009 to 2010 by 1,617 congestion event hours. In the first three months of 2010, there were 3,768 real-time, congestion-event hours compared to 5,385 real-time, congestion-event hours in the first three months of 2009. Real-time, congestion-event hours increased on the internal PJM interfaces, while the reciprocally coordinated flowgates between PJM and the Midwest ISO, transmission lines and transformers saw decreases. The AP South Interface was the largest contributor to congestion costs in the first three months of 2010. With $170.3 million in total congestion costs, it accounted for 49 percent of the total PJM congestion costs in the first three months of 2010. The top five constraints in terms of congestion costs together contributed $295.3 million, or 86 percent, of the total PJM congestion in the first three months of 2010. The top five constraints included the AP South interface, the AEP-DOM interface, the 5004/5005 interface, the Bedington – Black Oak interface and the East Frankfurt – Crete line.

- **Zonal Congestion.** In the first three months of 2010, the Dominion Control Zone experienced the highest congestion costs of the control zones in PJM with $68.8 million. The AP South interface, the AEP-DOM interface, the 5004/5005 interface, the Bedington – Black Oak interface, and the Cloverdale – Lexington line contributed $64.2 million, or 93 percent of the total Dominion Control Zone congestion costs (Table 7-51). The AP Control Zone had the second highest congestion cost in PJM in the first three months of 2010. The $66.8 million in congestion costs in the AP Control Zone represented a 43 percent increase from the $46.7 million in congestion costs the zone had experienced in the first three months of 2009. The AP South interface contributed $40.1 million, or 60 percent of the total AP Control Zone congestion cost.

3 In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non market mechanism, typically under traditional regulation. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[4] Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

- **Restructuring Responsibility for Grid Development.** FERC's recent decision in the *Primary Power* case and the currently pending *Central Transmission* case raise significant issues about the ownership of transmission, the resultant incentives to build new transmission facilities and the potential for competitive forces to reduce the cost of transmission.[5]

4 *See* 126 FERC ¶61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶61,051 (2008).

5 131 FERC ¶61,015 (April 13, 2010); *Central Transmission, LLC v. PJM Interconnection, L.L.C.*, Docket No. EL10-52.

Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the cost and geographical distribution of generation facilities and the geographical distribution of load. Total congestion costs increased by $38.4 million or 13 percent, from $306.9 million in the first three months of 2009 to $345.3 million in the first three months of 2010. Day-ahead congestion costs increased by $2.58 million or one percent, from $389.5 million in the first three months of 2009 to $392.1 million in the first three months of 2010. Balancing congestion costs increased by $35.8 million or 43 percent, from -$82.6 million in the first three months of 2009 to -$46.8 million in the first three months of 2010. Congestion costs were significantly higher in the Day-Ahead Market than in the balancing market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market. Day-ahead congestion frequency increased from 2009 to 2010 by 1,017 congestion event hours or five percent. In the first three months of 2010, there were 19,548 day-ahead, congestion-event hours compared to 18,531 day-ahead, congestion-event hours in the first three months of 2009. Real-time congestion frequency decreased from 2009 to 2010 by 1,617 congestion event hours. In the first three months of 2010, there were 3,768 real-time, congestion-event hours compared to 5,385 real-time, congestion-event hours in the first three months of 2009.

ARRs and FTRs served as an effective, but not total, hedge against congestion. ARR and FTR revenues hedged more than 100 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2008 to 2009 planning period. For the first ten months of the 2009 to 2010 planning period, ARR and FTR revenue hedged 95.4 percent of the total congestion costs within PJM.[6] FTRs were paid at 100 percent of the target allocation for the 2008 to 2009 planning year and 98.7 percent of the target allocation level for the first ten months of the 2009 to 2010 planning period. Revenue adequacy for a planning period is not final until the end of the period.

There are other ways to evaluate the effectiveness of ARRs as a hedge. The value of ARRs and ARRs converted to self scheduled FTRs was 4.3 percent of total energy charges to load for the first three months of 2010.

One constraint accounted for nearly half of total congestion costs in the first three months of 2010 and the top five constraints accounted for 86 percent of total congestion costs. The AP South Interface was the largest contributor to congestion costs in the first three months of 2010.

The congestion metric requires careful review. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[7] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. This is a cost only in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the system marginal price. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

As an example, total congestion costs in PJM in the first three months of 2010 were $345.3 million, which was comprised of load congestion payments of $91.3 million, negative generation credits of $270.4 million and negative explicit congestion of $16.4 million (see Table 7-2).

6 See the *2010 Quarterly State of the Market Report for PJM: January through March*, , Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-14, "ARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010."

7 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

Congestion

Total Calendar Year Congestion

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 through March 2010 (See 2009 SOM, Table 7-1)

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
2009	$719	(66%)	$26,550	3%
2010 (Jan - Mar)	$345	NA	$8,415	4%
Total	$9,591		$159,002	6%

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): January through March 2009 and 2010 (See 2009 SOM, Table 7-2)

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2009 (Jan - Mar)	$106.0	($227.3)	($26.5)	$306.9
2010 (Jan - Mar)	$91.3	($270.4)	($16.4)	$345.3

Monthly Congestion

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): Calendar years 2008 through March 2010 (See 2009 SOM, Table 7-3)

	2008	2009	2010
Jan	$231.0	$149.3	$218.5
Feb	$168.1	$83.0	$106.4
Mar	$86.4	$74.6	$20.4
Apr	$126.2	$25.6	
May	$182.8	$25.9	
Jun	$436.4	$49.8	
Jul	$359.8	$39.4	
Aug	$127.4	$72.1	
Sep	$124.8	$23.9	
Oct	$102.2	$42.7	
Nov	$93.0	$36.3	
Dec	$78.4	$96.4	
Total	$2,116.6	$719.0	$345.3

Congestion Component of LMP

Table 7-4 Annual average congestion component of LMP: January through March 2009 and 2010 (See 2009 SOM, Table 7-4)

	2009 (Jan - Mar)		2010 (Jan - Mar)	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$4.63	$4.68	$2.11	$1.73
AEP	($4.64)	($4.29)	($3.49)	($2.98)
AP	$0.42	$1.97	($1.04)	($0.33)
BGE	$5.79	$4.85	$4.64	$4.06
ComEd	($8.40)	($9.76)	($6.12)	($6.15)
DAY	($6.27)	($5.72)	($4.79)	($4.15)
DLCO	($8.88)	($8.13)	($4.39)	($2.67)
Dominion	$4.46	$4.19	$5.61	$4.52
DPL	$5.10	$5.19	$2.36	$2.18
JCPL	$4.18	$4.27	$1.77	$1.34
Met-Ed	$4.61	$4.36	$2.32	$1.71
PECO	$4.34	$3.99	$2.14	$1.72
PENELEC	($0.37)	($0.04)	($1.97)	($1.93)
Pepco	$5.79	$5.20	$5.69	$4.86
PPL	$4.30	$4.16	$2.23	$1.47
PSEG	$4.78	$5.04	$2.76	$3.31
RECO	$3.44	$3.81	$1.69	$0.44

Congested Facilities

Congestion by Facility Type and Voltage

Table 7-5 Congestion summary (By facility type): January through March 2010 (See 2009 SOM, Table 7-5)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($1.3)	($11.6)	$3.0	$13.4	($0.1)	$0.2	($0.8)	($1.1)	$12.3	1,773	172
Interface	$58.1	($228.0)	($2.1)	$284.0	$7.3	$4.5	$1.7	$4.6	$288.6	3,096	1,151
Line	$29.8	($37.0)	$10.1	$77.0	($13.0)	$8.0	($29.5)	($50.5)	$26.5	13,053	2,130
Transformer	$9.4	($5.7)	$1.0	$16.0	$0.3	($0.5)	($0.6)	$0.2	$16.3	1,626	315
Unclassified	$0.7	($0.2)	$0.7	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	NA	NA
Total	$96.7	($282.6)	$12.7	$392.1	($5.4)	$12.2	($29.1)	($46.8)	$345.3	19,548	3,768

Table 7-6 Congestion summary (By facility type): January through March 2009 (See 2009 SOM, Table 7-6)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	$4.0	($7.0)	$7.4	$18.4	($6.2)	$3.1	($37.7)	($47.0)	($28.6)	693	1,006
Interface	$27.3	($133.7)	$1.4	$162.4	$3.0	($2.9)	$1.8	$7.7	$170.1	1,901	580
Line	$43.5	($80.3)	$22.1	$145.9	($3.2)	$0.1	($14.9)	($18.2)	$127.7	13,439	2,566
Transformer	$43.9	$0.0	$16.7	$60.5	($7.8)	($6.3)	($23.6)	($25.2)	$35.4	2,498	1,233
Unclassified	$1.6	($0.3)	$0.4	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	NA	NA
Total	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	$306.9	18,531	5,385

Table 7-7 Congestion summary (By facility voltage): January through March 2010 (See 2009 SOM, Table 7-7)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.5	($1.7)	$0.5	$2.7	($1.1)	($0.1)	($3.2)	($4.2)	($1.5)	56	74
500	$62.6	($232.3)	($1.4)	$293.4	$6.6	$2.7	$0.6	$4.5	$297.9	3,440	1,399
345	$3.9	($18.6)	$3.8	$26.3	($3.7)	$2.2	($14.7)	($20.6)	$5.7	2,047	734
230	$8.5	($7.3)	$5.7	$21.6	($6.0)	$6.9	($9.4)	($22.3)	($0.7)	4,600	526
138	$15.1	($24.2)	$3.5	$42.7	($1.6)	($0.2)	($2.3)	($3.7)	$39.0	7,395	917
115	$5.0	$1.8	$0.1	$3.3	$0.2	$0.6	($0.1)	($0.4)	$2.9	407	111
69	$0.3	($0.1)	($0.0)	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.4	1,427	7
34	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	18	0
12	$0.1	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	158	0
Unclassified	$0.7	($0.2)	$0.7	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	NA	NA
Total	$96.7	($282.6)	$12.7	$392.1	($5.4)	$12.2	($29.1)	($46.8)	$345.3	19,548	3,768

Table 7-8 Congestion summary (By facility voltage): January through March 2009 (See 2009 SOM, Table 7-8)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
500	$57.6	($149.4)	$8.5	$215.5	$2.1	($10.8)	($5.7)	$7.3	$222.8	4,029	1,349
345	$19.4	($17.5)	$25.2	$62.1	($3.7)	$0.8	($32.7)	($37.3)	$24.8	3,256	896
230	$9.2	($6.3)	$2.5	$18.0	($0.6)	$1.8	($1.5)	($3.9)	$14.1	2,835	419
138	$28.4	($48.1)	$11.2	$87.7	($10.8)	$1.6	($34.3)	($46.6)	$41.0	6,703	2,423
115	$1.2	($0.0)	$0.1	$1.3	($0.0)	$0.0	($0.1)	($0.2)	$1.1	627	127
69	$2.8	$0.3	$0.1	$2.5	($1.2)	$0.6	($0.0)	($1.8)	$0.7	1,081	171
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
12	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Unclassified	$1.6	($0.3)	$0.4	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	NA	NA
Total	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	$306.9	18,531	5,385

Constraint Duration

Table 7-9 Top 25 constraints with frequent occurrence: January through March 2009 and 2010 (See 2009 SOM, Table 7-9)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2009	2010	Change	2009	2010	Change	2009	2010	Change	2009	2010	Change
1	Athenia - Saddlebrook	Line	769	1,779	1,010	108	273	165	36%	82%	47%	5%	13%	8%
2	AP South	Interface	1,088	1,255	167	216	735	519	50%	58%	8%	10%	34%	24%
3	East Frankfort - Crete	Line	912	835	(77)	66	418	352	42%	39%	(4%)	3%	19%	16%
4	5004/5005 Interface	Interface	256	806	550	191	294	103	12%	37%	25%	9%	14%	5%
5	Waterman - West Dekalb	Line	424	812	388	9	159	150	20%	38%	18%	0%	7%	7%
6	Rising	Flowgate	0	582	582	3	32	29	0%	27%	27%	0%	1%	1%
7	Pleasant Prairie - Zion	Flowgate	0	556	556	45	21	(24)	0%	26%	26%	2%	1%	(1%)
8	AEP-DOM	Interface	96	452	356	56	76	20	4%	21%	16%	3%	4%	1%
9	Bedington - Black Oak	Interface	58	519	461	55	9	(46)	3%	24%	21%	3%	0%	(2%)
10	Burlington - Croydon	Line	511	512	1	0	13	13	24%	24%	0%	0%	1%	1%
11	Bayonne - PVSC	Line	102	507	405	0	0	0	5%	23%	19%	0%	0%	0%
12	Hawthorn - Waldwick	Line	0	454	454	0	36	36	0%	21%	21%	0%	2%	2%
13	Tiltonsville - Windsor	Line	0	437	437	0	0	0	0%	20%	20%	0%	0%	0%
14	Bellehaven - Tasley	Line	18	429	411	0	0	0	1%	20%	19%	0%	0%	0%
15	Tiltonsville - Windsor	Line	348	260	(88)	87	139	52	16%	12%	(4%)	4%	6%	2%
16	Crescent	Transformer	0	310	310	1	58	57	0%	14%	14%	0%	3%	3%
17	Pleasant Valley - Belvidere	Line	477	274	(203)	78	68	(10)	22%	13%	(9%)	4%	3%	(0%)
18	Sammis - Wylie Ridge	Line	615	305	(310)	101	37	(64)	28%	14%	(14%)	5%	2%	(3%)
19	Athenia - Kuller Road	Line	2	335	333	0	0	0	0%	16%	15%	0%	0%	0%
20	Lindenwold - Stratford	Line	181	318	137	0	0	0	8%	15%	6%	0%	0%	0%
21	Pinehill - Stratford	Line	530	293	(237)	0	0	0	25%	14%	(11%)	0%	0%	0%
22	State Line - Wolf Lake	Flowgate	38	269	231	14	0	(14)	2%	12%	11%	1%	0%	(1%)
23	Cloverdale - Lexington	Line	571	154	(417)	220	94	(126)	26%	7%	(19%)	10%	4%	(6%)
24	Hawthorn - Hinchmans Ave	Line	0	209	209	0	35	35	0%	10%	10%	0%	2%	2%
25	Albright - Snowy Creek	Line	0	226	226	0	2	2	0%	10%	10%	0%	0%	0%

Table 7-10 Top 25 constraints with largest year-to-year change in occurrence: January through March 2009 and 2010 (See 2009 SOM, Table 7-10)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2009	2010	Change	2009	2010	Change	2009	2010	Change	2009	2010	Change
1	Kammer	Transformer	1,021	0	(1,021)	504	0	(504)	47%	0%	(47%)	23%	0%	(23%)
2	Athenia - Saddlebrook	Line	769	1,779	1,010	108	273	165	36%	82%	47%	5%	13%	8%
3	Kammer - Ormet	Line	514	0	(514)	509	0	(509)	24%	0%	(24%)	24%	0%	(24%)
4	Ruth - Turner	Line	514	18	(496)	245	11	(234)	24%	1%	(23%)	11%	1%	(11%)
5	Wylie Ridge	Transformer	354	0	(354)	335	2	(333)	16%	0%	(16%)	16%	0%	(15%)
6	AP South	Interface	1,088	1,255	167	216	735	519	50%	58%	8%	10%	34%	24%
7	5004/5005 Interface	Interface	256	806	550	191	294	103	12%	37%	25%	9%	14%	5%
8	Rising	Flowgate	0	582	582	3	32	29	0%	27%	27%	0%	1%	1%
9	Leonia - New Milford	Line	632	68	(564)	14	0	(14)	29%	3%	(26%)	1%	0%	(1%)
10	Dunes Acres - Michigan City	Flowgate	429	142	(287)	270	3	(267)	20%	7%	(13%)	13%	0%	(12%)
11	Cloverdale - Lexington	Line	571	154	(417)	220	94	(126)	26%	7%	(19%)	10%	4%	(6%)
12	Waterman - West Dekalb	Line	424	812	388	9	159	150	20%	38%	18%	0%	7%	7%
13	Pleasant Prairie - Zion	Flowgate	0	556	556	45	21	(24)	0%	26%	26%	2%	1%	(1%)
14	Hawthorn - Waldwick	Line	0	454	454	0	36	36	0%	21%	21%	0%	2%	2%
15	Glidden - West Dekalb	Line	582	108	(474)	0	0	0	27%	5%	(22%)	0%	0%	0%
16	Tiltonsville - Windsor	Line	0	437	437	0	0	0	0%	20%	20%	0%	0%	0%
17	Bedington - Black Oak	Interface	58	519	461	55	9	(46)	3%	24%	21%	3%	0%	(2%)
18	Bellehaven - Tasley	Line	18	429	411	0	0	0	1%	20%	19%	0%	0%	0%
19	Bayonne - PVSC	Line	102	507	405	0	0	0	5%	23%	19%	0%	0%	0%
20	Plainsboro - Trenton	Line	275	0	(275)	113	0	(113)	13%	0%	(13%)	5%	0%	(5%)
21	AEP-DOM	Interface	96	452	356	56	76	20	4%	21%	16%	3%	4%	1%
22	Sammis - Wylie Ridge	Line	615	305	(310)	101	37	(64)	28%	14%	(14%)	5%	2%	(3%)
23	Crescent	Transformer	0	310	310	1	58	57	0%	14%	14%	0%	3%	3%
24	West	Interface	380	56	(324)	55	37	(18)	18%	3%	(15%)	3%	2%	(1%)
25	Bedington	Transformer	236	0	(236)	103	0	(103)	11%	0%	(11%)	5%	0%	(5%)

Constraint Costs

Table 7-11 Top 25 constraints affecting annual PJM congestion costs (By facility): January through March 2010 (See 2009 SOM, Table 7-11)

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2010
1	AP South	Interface	500	$13.4	($156.4)	($1.2)	$168.6	$5.1	$4.5	$1.2	$1.7	$170.3	49%
2	AEP-DOM	Interface	500	$9.8	($37.5)	$0.8	$48.1	$0.2	($1.2)	$0.1	$1.6	$49.7	14%
3	5004/5005 Interface	Interface	500	$26.3	($16.9)	($0.9)	$42.2	$1.3	$1.3	$0.2	$0.3	$42.5	12%
4	Bedington - Black Oak	Interface	500	$6.0	($17.2)	($0.8)	$22.4	$0.4	($0.5)	$0.1	$0.9	$23.3	7%
5	East Frankfort - Crete	Line	ComEd	$3.4	($11.8)	$1.7	$16.9	($2.5)	$0.8	($4.2)	($7.5)	$9.5	3%
6	Crescent	Transformer	DLCO	$2.9	($2.0)	$0.2	$5.1	$0.0	($0.6)	($0.2)	$0.3	$5.4	2%
7	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($2.4)	($5.9)	$1.5	$5.1	($0.5)	$1.0	($8.6)	($10.2)	($5.1)	(1%)
8	Mount Storm - Pruntytown	Line	AP	$1.3	($2.7)	$0.1	$4.1	($0.2)	($0.7)	$0.1	$0.6	$4.7	1%
9	Athenia - Saddlebrook	Line	PSEG	$3.4	($2.7)	$5.6	$11.6	($6.7)	$4.3	($5.0)	($16.0)	($4.4)	(1%)
10	Rising	Flowgate	Midwest ISO	$0.2	($3.5)	$0.4	$4.2	($0.0)	($0.0)	($0.0)	($0.0)	$4.1	1%
11	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	($0.0)	$0.0	($0.6)	$0.9	($2.5)	($4.0)	($4.0)	(1%)
12	Baker - Broadford	Line	AEP	($0.0)	($0.3)	$0.0	$0.4	($1.1)	($0.1)	($3.2)	($4.2)	($3.8)	(1%)
13	Kanawha River	Transformer	AEP	$1.3	($1.6)	$0.2	$3.1	$0.0	($0.1)	($0.0)	$0.0	$3.2	1%
14	West	Interface	500	$2.5	($0.1)	$0.0	$2.7	$0.3	$0.4	$0.2	$0.1	$2.8	1%
15	Culloden - Wyoming	Line	AEP	$0.5	($1.4)	$0.4	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	1%
16	Kanawha - Kincaid	Line	AEP	$1.4	($0.8)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	1%
17	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.2)	($0.2)	($0.2)	$0.3	($1.5)	($2.0)	($2.2)	(1%)
18	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.7	($1.3)	($2.2)	($2.2)	(1%)
19	Cloverdale - Lexington	Line	AEP	$1.5	($0.6)	$0.2	$2.4	($0.2)	($0.5)	($0.5)	($0.2)	$2.1	1%
20	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.6	($1.1)	$0.4	$2.1	($0.0)	($0.0)	($0.0)	($0.0)	$2.1	1%
21	Waterman - West Dekalb	Line	ComEd	($1.0)	($2.9)	$0.3	$2.2	$0.2	$0.2	($0.4)	($0.4)	$1.9	1%
22	Collier - Elwyn	Line	DLCO	$1.8	$0.1	$0.0	$1.8	($0.0)	($0.1)	($0.0)	$0.0	$1.8	1%
23	Sammis - Wylie Ridge	Line	AP	$2.5	$0.4	$0.1	$2.3	($0.4)	($0.2)	($0.3)	($0.5)	$1.7	0%
24	Harrison - Pruntytown	Line	500	$1.1	($0.8)	$0.3	$2.1	($0.4)	($0.5)	($0.6)	($0.5)	$1.6	0%
25	Unclassified	Unclassified	Unclassified	$0.7	($0.2)	$0.7	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	0%

Table 7-12 Top 25 constraints affecting annual PJM congestion costs (By facility): January through March 2009 (See 2009 SOM, Table 7-12)

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2009
1	AP South	Interface	500	$3.3	($91.7)	($0.3)	$94.6	$2.6	($3.1)	$2.0	$7.7	$102.3	33%
2	West	Interface	500	$17.7	($21.4)	$0.5	$39.6	$0.3	($0.1)	($0.1)	$0.4	$40.0	13%
3	5004/5005 Interface	Interface	500	$5.2	($14.5)	$0.8	$20.5	$1.0	$0.3	$0.0	$0.7	$21.2	7%
4	Mount Storm - Pruntytown	Line	AP	$1.7	($16.4)	$0.4	$18.6	$1.1	($0.7)	($0.2)	$1.7	$20.3	7%
5	Kammer	Transformer	500	$21.9	$7.8	$5.3	$19.4	($1.8)	($4.3)	($5.5)	($3.1)	$16.3	5%
6	East Frankfort - Crete	Line	ComEd	$3.3	($8.1)	$5.5	$16.9	($0.0)	($0.1)	($1.7)	($1.6)	$15.3	5%
7	Cloverdale - Lexington	Line	AEP	$6.0	($3.7)	$1.5	$11.3	($0.0)	($2.6)	($1.8)	$0.7	$12.0	4%
8	Pana North	Flowgate	Midwest ISO	$0.0	($0.3)	$0.3	$0.6	($0.4)	$0.9	($10.5)	($11.8)	($11.1)	(4%)
9	Ruth - Turner	Line	AEP	$2.2	($5.9)	$0.5	$8.6	($1.2)	($0.6)	($0.6)	($1.2)	$7.4	2%
10	Pleasant Valley - Belvidere	Line	ComEd	($1.3)	($8.4)	$0.8	$7.8	$0.8	$0.4	($1.2)	($0.9)	$6.9	2%
11	Kanawha River	Transformer	AEP	$2.0	($3.6)	$0.3	$5.8	$0.1	($0.5)	($0.1)	$0.5	$6.3	2%
12	Kammer - Ormet	Line	AEP	$4.2	($4.1)	($0.1)	$8.2	($1.6)	$0.5	($0.0)	($2.2)	$6.1	2%
13	Sammis - Wylie Ridge	Line	AP	$3.1	($2.7)	$3.4	$9.1	($0.8)	($0.3)	($2.6)	($3.2)	$5.9	2%
14	Kanawha - Kincaid	Line	AEP	$1.9	($3.5)	$0.2	$5.6	$0.0	$0.0	$0.0	$0.0	$5.6	2%
15	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	(2%)
16	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.4	($4.2)	$5.5	$13.1	($3.9)	($0.0)	($14.7)	($18.5)	($5.4)	(2%)
17	Kanawha River - Bradley	Line	AEP	($0.1)	($4.6)	$0.3	$4.7	($0.0)	$0.1	($0.0)	($0.1)	$4.7	2%
18	Mount Storm	Transformer	AP	$0.7	($3.3)	($0.1)	$3.9	($0.1)	($0.0)	$0.1	$0.0	$3.9	1%
19	Bedington - Black Oak	Interface	500	$0.6	($3.5)	$0.0	$4.1	($0.4)	($0.0)	$0.2	($0.3)	$3.9	1%
20	Glidden - West Dekalb	Line	ComEd	($0.3)	($3.5)	$0.3	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	1%
21	Breed - Wheatland	Line	AEP	($0.1)	($3.2)	$0.4	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	1%
22	Sliver Lake - Cherry Valley	Line	ComEd	($0.1)	($2.4)	$0.5	$2.8	$0.0	$0.0	($0.0)	($0.0)	$2.8	1%
23	Bedington - Harmony	Line	AP	$1.1	($1.2)	$0.5	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1%
24	AEP-DOM	Interface	500	$0.4	($2.7)	$0.3	$3.4	($0.5)	($0.0)	($0.3)	($0.8)	$2.6	1%
25	Burnham - Munster	Line	ComEd	$0.5	($0.9)	$1.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	1%

Congestion-Event Summary for Midwest ISO Flowgates

Table 7-13 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through March 2010 (See 2009 SOM, Table 7-13)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pleasant Prairie - Zion	($2.4)	($5.9)	$1.5	$5.1	($0.5)	$1.0	($8.6)	($10.2)	($5.1)	556	21
2	Rising	$0.2	($3.5)	$0.4	$4.2	($0.0)	($0.0)	($0.0)	($0.0)	$4.1	582	32
3	Dunes Acres - Michigan City	$0.6	($1.1)	$0.4	$2.1	($0.0)	($0.0)	($0.0)	($0.0)	$2.1	142	3
4	State Line - Wolf Lake	$0.3	($0.5)	$0.5	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	269	0
5	Crete - St Johns Tap	$0.1	($0.2)	$0.1	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.3	129	1
6	Bunsonville - Eugene	($0.0)	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
7	Burr Oak	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.1	($0.1)	($0.2)	($0.2)	20	40
8	Benton Harbor - Palisades	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.1)	($0.1)	0	1
9	Powerton Jct. - Lilly	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.1)	0	15
10	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	9
11	Oak Grove - Galesburg	($0.1)	($0.2)	$0.1	$0.2	$0.0	$0.0	($0.2)	($0.2)	$0.0	51	38
12	State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	6
13	Coffeen North - Ramsey	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	3
14	Lanesville	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	2
15	Krendale - Seneca	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	1

Table 7-14 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): January through March 2009 (See 2009 SOM, Table 7-14)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pana North	$0.0	($0.3)	$0.3	$0.6	($0.4)	$0.9	($10.5)	($11.8)	($11.1)	92	247
2	Schahfer - Burr Oak	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	62	81
3	Dunes Acres - Michigan City	$3.4	($4.2)	$5.5	$13.1	($3.9)	($0.0)	($14.7)	($18.5)	($5.4)	429	270
4	Pleasant Prairie - Zion	($0.0)	($0.1)	$0.0	$0.1	$0.3	$0.5	($1.9)	($2.2)	($2.1)	0	45
5	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4	($1.3)	($1.7)	($1.7)	0	72
6	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($1.0)	($1.2)	($1.2)	0	30
7	Oak Grove - Galesburg	($0.0)	($0.2)	$0.1	$0.2	$0.3	$0.4	($1.2)	($1.4)	($1.1)	0	175
8	Crete - St Johns Tap	$0.1	($0.7)	$0.3	$1.1	($0.1)	$0.0	($0.3)	($0.4)	$0.7	48	3
9	Lanesville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	($0.4)	0	10
10	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.3	($0.0)	($0.4)	($0.4)	0	4
11	Burr Oak	$0.1	($0.2)	$0.4	$0.7	($0.2)	$0.1	($0.6)	($0.9)	($0.2)	24	30
12	State Line - Wolf Lake	$0.0	($0.1)	$0.1	$0.2	($0.0)	($0.0)	($0.1)	($0.1)	$0.1	38	14
13	State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	0	6
14	Rising	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	0	3
15	Havana - Ipava	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	9
16	Krendale - Seneca	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	2
17	Ontario Hydro - NYISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	0	2
18	Whitestown - Guion	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	0	3
19	State Line	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0

Congestion-Event Summary for the 500 kV System

Table 7-15 Regional constraints summary (By facility): January through March 2010 (See 2009 SOM, Table 7-15)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$13.4	($156.4)	($1.2)	$168.6	$5.1	$4.5	$1.2	$1.7	$170.3	1,255	735
2	AEP-DOM	Interface	500	$9.8	($37.5)	$0.8	$48.1	$0.2	($1.2)	$0.1	$1.6	$49.7	452	76
3	5004/5005 Interface	Interface	500	$26.3	($16.9)	($0.9)	$42.2	$1.3	$1.3	$0.2	$0.3	$42.5	806	294
4	Bedington - Black Oak	Interface	500	$6.0	($17.2)	($0.8)	$22.4	$0.4	($0.5)	$0.1	$0.9	$23.3	519	9
5	West	Interface	500	$2.5	($0.1)	$0.0	$2.7	$0.3	$0.4	$0.2	$0.1	$2.8	56	37
6	Harrison - Pruntytown	Line	500	$1.1	($0.8)	$0.3	$2.1	($0.4)	($0.5)	($0.6)	($0.5)	$1.6	75	86
7	Harrison Tap - North Longview	Line	500	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	6	0
8	Central	Interface	500	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	8	0

Table 7-16 Regional constraints summary (By facility): January through March 2009 (See 2009 SOM, Table 7-16)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$3.3	($91.7)	($0.3)	$94.6	$2.6	($3.1)	$2.0	$7.7	$102.3	1,088	216
2	West	Interface	500	$17.7	($21.4)	$0.5	$39.6	$0.3	($0.1)	($0.1)	$0.4	$40.0	380	55
3	5004/5005 Interface	Interface	500	$5.2	($14.5)	$0.8	$20.5	$1.0	$0.3	$0.0	$0.7	$21.2	256	191
4	Kammer	Transformer	500	$21.9	$7.8	$5.3	$19.4	($1.8)	($4.3)	($5.5)	($3.1)	$16.3	1,021	504
5	Bedington - Black Oak	Interface	500	$0.6	($3.5)	$0.0	$4.1	($0.4)	($0.0)	$0.2	($0.3)	$3.9	58	55
6	AEP-DOM	Interface	500	$0.4	($2.7)	$0.3	$3.4	($0.5)	($0.0)	($0.3)	($0.8)	$2.6	96	56
7	East	Interface	500	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	11	0
8	Central	Interface	500	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.1	$0.0	($0.1)	$0.0	12	7
9	Harrison - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	3

Zonal Congestion

Summary

Table 7-17 Congestion cost summary (By control zone): January through March 2010 (See 2009 SOM, Table 7-17)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$5.2	$2.5	$0.0	$2.7	$0.5	($0.0)	($0.0)	$0.5	$3.2
AEP	($16.0)	($87.0)	$3.0	$73.9	($6.6)	$3.6	($4.2)	($14.4)	$59.6
AP	($16.0)	($83.5)	($2.0)	$65.5	$2.4	$2.8	$1.6	$1.3	$66.8
BGE	$37.6	$28.3	$1.6	$10.9	$3.8	($1.5)	($1.5)	$3.8	$14.7
ComEd	($86.5)	($151.6)	($0.8)	$64.3	($2.7)	$4.0	($2.3)	($9.1)	$55.2
DAY	($3.7)	($7.1)	($0.1)	$3.2	$0.0	$0.5	$0.1	($0.4)	$2.8
DLCO	($29.8)	($46.8)	($0.1)	$16.9	($1.7)	($0.8)	($0.0)	($1.0)	$15.9
Dominion	$74.1	$4.3	$1.8	$71.6	$1.6	$3.1	($1.3)	($2.7)	$68.8
DPL	$12.0	$3.4	($0.1)	$8.5	$0.7	($0.4)	$0.1	$1.2	$9.7
External	($19.1)	($26.7)	($2.2)	$5.4	$3.3	($2.0)	($9.2)	($3.9)	$1.5
JCPL	$10.6	$3.9	$0.0	$6.7	($0.0)	($0.2)	($0.1)	$0.1	$6.8
Met-Ed	$10.2	$7.3	($0.0)	$2.8	$0.0	($0.5)	($0.0)	$0.5	$3.3
PECO	$9.5	$19.0	$0.0	($9.5)	($0.1)	$0.1	($0.0)	($0.3)	($9.7)
PENELEC	($29.7)	($61.4)	($0.2)	$31.6	$4.1	$0.8	$0.1	$3.5	$35.1
Pepco	$85.9	$62.6	$1.4	$24.6	($3.9)	($2.9)	($1.6)	($2.6)	$22.1
PPL	$24.9	$29.8	$0.8	($4.1)	$0.8	$0.4	($0.3)	$0.0	($4.1)
PSEG	$27.1	$20.2	$9.6	$16.5	($7.7)	$5.0	($10.6)	($23.3)	($6.9)
RECO	$0.6	$0.1	$0.0	$0.5	$0.0	$0.1	$0.0	($0.1)	$0.4
Total	$96.7	($282.6)	$12.7	$392.1	($5.4)	$12.2	($29.1)	($46.8)	$345.3

Table 7-18 Congestion cost summary (By control zone): January through March 2009 (See 2009 SOM, Table 7-18)

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$13.3	$5.7	$0.2	$7.7	($0.9)	$0.6	$0.4	($1.1)	$6.6
AEP	($35.2)	($82.8)	$6.5	$54.1	($2.7)	$4.0	($7.7)	($14.4)	$39.7
AP	$8.5	($49.5)	$8.2	$66.1	($4.5)	($0.9)	($15.8)	($19.4)	$46.7
BGE	$40.5	$35.6	$0.7	$5.6	$3.8	($3.4)	($0.6)	$6.5	$12.1
ComEd	($99.1)	($180.4)	$0.1	$81.4	($5.9)	($1.0)	($1.5)	($6.4)	$74.9
DAY	($5.6)	($9.9)	$0.1	$4.4	$0.6	$1.3	($0.1)	($0.8)	$3.6
DLCO	($31.7)	($48.9)	($0.0)	$17.1	($2.7)	$3.9	($0.0)	($6.7)	$10.5
Dominion	$35.6	($5.4)	$3.5	$44.5	$0.8	($4.3)	($3.2)	$1.9	$46.4
DPL	$28.0	$9.8	$0.3	$18.5	($0.3)	$1.1	($0.3)	($1.7)	$16.8
External	($12.7)	($32.3)	$19.2	$38.8	$0.3	($2.9)	($40.7)	($37.6)	$1.2
JCPL	$27.6	$10.7	$0.1	$17.0	$0.1	($1.6)	($0.1)	$1.5	$18.5
Met-Ed	$21.3	$21.3	$0.1	$0.1	($0.4)	($0.8)	($0.1)	$0.3	$0.4
PECO	$8.7	$20.5	$0.1	($11.7)	($0.4)	($0.1)	($0.0)	($0.4)	($12.1)
PENELEC	($4.4)	($21.0)	$0.4	$17.0	$0.9	$1.2	($0.2)	($0.4)	$16.6
Pepco	$76.7	$57.6	$0.9	$20.1	($2.1)	($5.3)	($0.9)	$2.3	$22.4
PPL	$7.0	$11.3	$1.9	($2.4)	$0.2	($1.2)	($0.0)	$1.3	($1.1)
PSEG	$40.4	$36.3	$5.8	$9.9	($0.9)	$3.2	($3.3)	($7.3)	$2.6
RECO	$1.4	$0.0	$0.1	$1.4	($0.1)	($0.0)	($0.1)	($0.2)	$1.2
Total	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	$306.9

Details of Regional and Zonal Congestion

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-19 AECO Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-19)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$3.6	$1.8	$0.0	$1.9	$0.2	($0.0)	($0.0)	$0.3	$2.1	806	294
2	East Frankfort - Crete	Line	ComEd	$0.3	$0.1	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.3	835	418
3	AP South	Interface	500	$0.6	$0.3	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.1	$0.3	1,255	735
4	Athenia - Saddlebrook	Line	PSEG	($0.2)	($0.1)	($0.0)	($0.1)	($0.1)	$0.0	$0.0	($0.1)	($0.3)	1,779	273
5	West	Interface	500	$0.3	$0.1	$0.0	$0.1	$0.1	$0.0	$0.0	$0.1	$0.2	56	37
6	Sammis - Wylie Ridge	Line	AP	$0.2	$0.1	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	305	37
7	Graceton - Raphael Road	Line	BGE	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.1)	($0.1)	34	25
8	Bedington - Black Oak	Interface	500	$0.2	$0.1	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	519	9
9	Tiltonsville - Windsor	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.1	260	139
10	Crescent	Transformer	DLCO	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	310	58
11	Harrison - Pruntytown	Line	500	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	75	86
12	Cloverdale - Lexington	Line	AEP	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	154	94
13	Doubs	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	20	33
14	Atlantic - Larrabee	Line	JCPL	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	88	6
15	AEP-DOM	Interface	500	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	452	76
47	Lindenwold - Stratford	Line	AECO	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	318	0
102	Pinehill - Stratford	Line	AECO	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	293	0
171	Berlin - Silver Lake	Line	AECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0

Table 7-20 AECO Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-20)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$4.5	$2.2	$0.0	$2.4	$0.0	($0.0)	($0.0)	$0.0	$2.4	380	55
2	Kammer	Transformer	500	$1.5	$0.7	$0.0	$0.9	$0.1	($0.0)	$0.0	$0.1	$1.0	1,021	504
3	5004/5005 Interface	Interface	500	$1.8	$0.9	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$1.0	256	191
4	Wylie Ridge	Transformer	AP	$1.8	$0.9	$0.0	$0.9	($0.0)	$0.1	$0.1	($0.0)	$0.9	354	335
5	Absecon - Lewis	Line	AECO	$1.0	$0.1	$0.0	$1.0	($1.2)	$0.5	($0.0)	($1.7)	($0.8)	22	149
6	AP South	Interface	500	$0.6	$0.3	$0.0	$0.3	$0.0	$0.0	$0.1	$0.1	$0.4	1,088	216
7	Sammis - Wylie Ridge	Line	AP	$0.6	$0.2	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.4	615	101
8	Cloverdale - Lexington	Line	AEP	$0.4	$0.2	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.1	$0.3	571	220
9	East Frankfort - Crete	Line	ComEd	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	912	0
10	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.2	$0.1	($0.0)	$0.1	$0.1	($0.0)	$0.0	$0.1	$0.2	429	270
11	Lewis - Motts - Cedar	Line	AECO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	108	0
12	Tiltonsville - Windsor	Line	AP	$0.1	$0.1	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	348	87
13	Atlantic - Larrabee	Line	JCPL	($0.1)	($0.0)	$0.0	($0.1)	($0.0)	($0.0)	$0.0	($0.0)	($0.1)	63	18
14	Mount Storm - Pruntytown	Line	AP	$0.2	$0.1	$0.0	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	455	17
15	Athenia - Saddlebrook	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	($0.1)	769	108
37	Monroe	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	106	0
38	Clayton - Williams	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
51	Shieldalloy - Vineland	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
67	Carlls Corner - Sherman Ave	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
69	Pinehill - Stratford	Line	AECO	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	530	0

BGE Control Zone

Table 7-21 BGE Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-21)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$19.9	$15.8	$0.8	$4.9	$2.0	($0.8)	($0.8)	$2.0	$7.0	1,255	735
2	5004/5005 Interface	Interface	500	$4.3	$2.2	$0.2	$2.3	$0.2	($0.2)	($0.1)	$0.2	$2.5	806	294
3	Bedington - Black Oak	Interface	500	$4.1	$3.1	$0.2	$1.2	$0.2	($0.0)	($0.0)	$0.2	$1.4	519	9
4	East Frankfort - Crete	Line	ComEd	$1.1	$0.8	$0.0	$0.3	$0.2	($0.1)	($0.0)	$0.2	$0.6	835	418
5	AEP-DOM	Interface	500	$3.1	$2.8	$0.1	$0.3	$0.2	($0.0)	($0.0)	$0.2	$0.5	452	76
6	West	Interface	500	$0.6	$0.4	$0.0	$0.3	$0.2	($0.1)	($0.0)	$0.2	$0.4	56	37
7	Mount Storm - Pruntytown	Line	AP	$0.6	$0.5	$0.0	$0.2	$0.1	($0.1)	($0.0)	$0.2	$0.3	87	64
8	Harrison - Pruntytown	Line	500	$0.2	$0.2	$0.0	$0.1	$0.2	($0.1)	($0.0)	$0.2	$0.3	75	86
9	Graceton - Raphael Road	Line	BGE	$0.6	$0.3	$0.0	$0.3	$0.1	$0.1	($0.1)	($0.0)	$0.3	34	25
10	Doubs	Transformer	AP	$0.2	$0.2	$0.0	$0.1	$0.1	($0.2)	($0.0)	$0.2	$0.3	20	33
11	Sammis - Wylie Ridge	Line	AP	$0.5	$0.4	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	305	37
12	Cloverdale - Lexington	Line	AEP	$0.3	$0.3	$0.0	$0.1	$0.1	($0.0)	($0.1)	$0.1	$0.2	154	94
13	Athenia - Saddlebrook	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	($0.1)	$0.0	$0.0	($0.1)	($0.2)	1,779	273
14	Nipetown - Reid	Line	AP	$0.3	$0.2	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	75	18
15	Messic Road - Morgan	Line	AP	$0.3	$0.2	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	172	0
24	Fullerton - Windyedge	Line	BGE	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4	0
31	Graceton - Safe Harbor	Line	BGE	$0.2	$0.1	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	15	1
46	Brandon Shores - Riverside	Line	BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	5	15
54	Conastone - Otter	Line	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	3	1
66	Glenarm - Windy Edge	Line	BGE	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0

Table 7-22 BGE Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-22)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$11.6	$11.4	$0.1	$0.3	$0.9	($0.9)	($0.1)	$1.8	$2.1	1,088	216
2	Kammer	Transformer	500	$4.7	$3.8	$0.1	$1.0	$0.6	($0.5)	($0.1)	$0.9	$1.9	1,021	504
3	West	Interface	500	$8.1	$6.8	$0.2	$1.4	$0.1	($0.1)	($0.0)	$0.2	$1.6	380	55
4	Wylie Ridge	Transformer	AP	$3.6	$3.4	$0.1	$0.3	$0.6	($0.7)	($0.2)	$1.2	$1.5	354	335
5	5004/5005 Interface	Interface	500	$1.3	$0.7	$0.1	$0.6	$0.2	($0.2)	($0.1)	$0.4	$1.0	256	191
6	Mount Storm - Pruntytown	Line	AP	$3.1	$2.9	$0.0	$0.2	$0.3	($0.2)	($0.0)	$0.5	$0.8	455	17
7	Cloverdale - Lexington	Line	AEP	$2.1	$2.0	$0.0	$0.2	$0.2	($0.1)	($0.0)	$0.3	$0.5	571	220
8	Sammis - Wylie Ridge	Line	AP	$1.3	$1.1	$0.0	$0.2	$0.1	($0.1)	($0.0)	$0.1	$0.4	615	101
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.5	$0.4	$0.0	$0.1	$0.2	($0.1)	($0.0)	$0.2	$0.3	429	270
10	Bedington - Black Oak	Interface	500	$0.7	$0.7	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.1	$0.2	58	55
11	Tiltonsville - Windsor	Line	AP	$0.4	$0.3	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.2	348	87
12	East Frankfort - Crete	Line	ComEd	$0.9	$0.7	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	912	0
13	AEP-DOM	Interface	500	$0.3	$0.2	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.2	96	56
14	Conastone	Transformer	BGE	$0.3	$0.2	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.2	8	1
15	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.1	$0.1	$0.0	$0.1	$0.0	($0.1)	($0.0)	$0.1	$0.2	62	81
35	Graceton - Raphael Road	Line	BGE	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	4	3
60	Concord - Green Street	Line	BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
63	Conastone - Northwest	Line	BGE	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
112	Green Street - Westport	Line	BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	72	0

DPL Control Zone

Table 7-23 DPL Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-23)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$7.1	$2.1	$0.0	$4.9	$0.2	$0.1	($0.0)	$0.1	$5.0	806	294
2	AP South	Interface	500	$2.0	$0.7	($0.0)	$1.3	$0.1	$0.0	$0.0	$0.1	$1.4	1,255	735
3	Indian River At20	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	$0.3	($0.6)	($0.0)	$0.9	$0.9	0	8
4	East Frankfort - Crete	Line	ComEd	$0.7	$0.1	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	835	418
5	Bedington - Black Oak	Interface	500	$0.6	$0.2	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	519	9
6	West	Interface	500	$0.5	$0.2	$0.0	$0.3	$0.1	$0.1	($0.0)	$0.0	$0.3	56	37
7	Sammis - Wylie Ridge	Line	AP	$0.4	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	305	37
8	Athenia - Saddlebrook	Line	PSEG	($0.4)	($0.1)	($0.0)	($0.3)	($0.0)	($0.0)	$0.0	$0.0	($0.3)	1,779	273
9	Bellehaven - Tasley	Line	DPL	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	429	0
10	Graceton - Raphael Road	Line	BGE	($0.2)	($0.1)	($0.0)	($0.1)	($0.0)	($0.0)	$0.0	($0.0)	($0.2)	34	25
11	Harrison - Pruntytown	Line	500	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.1	75	86
12	Tiltonsville - Windsor	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.1	260	139
13	Cloverdale - Lexington	Line	AEP	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.1	154	94
14	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	142	3
15	Longwood - Wye Mills	Line	DPL	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	11	0
18	Cecil - Colora	Line	DPL	$0.0	($0.0)	$0.0	$0.0	($0.1)	$0.0	($0.0)	($0.1)	($0.1)	17	4
27	New Church - Piney Grove	Line	DPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	49	0
30	Oak Hall	Transformer	DPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	44	0
31	Hallwood - Oak Hall	Line	DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	119	0
33	Church	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

Table 7-24 DPL Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-24)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$8.6	$3.5	$0.0	$5.1	($0.0)	$0.0	($0.0)	($0.1)	$5.0	380	55
2	Kammer	Transformer	500	$3.2	$0.8	$0.0	$2.4	($0.1)	$0.1	($0.0)	($0.2)	$2.2	1,021	504
3	Wylie Ridge	Transformer	AP	$3.4	$1.3	$0.0	$2.1	$0.2	$0.2	($0.0)	($0.0)	$2.1	354	335
4	5004/5005 Interface	Interface	500	$3.5	$1.5	$0.0	$2.0	$0.0	$0.2	($0.1)	($0.3)	$1.8	256	191
5	AP South	Interface	500	$1.7	$0.6	$0.0	$1.2	$0.0	$0.1	($0.0)	($0.0)	$1.1	1,088	216
6	Sammis - Wylie Ridge	Line	AP	$1.2	$0.2	$0.0	$0.9	($0.0)	($0.0)	($0.0)	($0.0)	$0.9	615	101
7	Cloverdale - Lexington	Line	AEP	$0.8	$0.2	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.0)	$0.6	571	220
8	Church - I.B. Corners	Line	DPL	$0.7	$0.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	39	0
9	East Frankfort - Crete	Line	ComEd	$0.7	$0.1	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	912	0
10	Edgemoor - Harmony	Line	DPL	$0.8	$0.3	$0.0	$0.5	($0.1)	($0.0)	($0.0)	($0.1)	$0.4	28	7
11	Red Lion At20	Transformer	DPL	$0.4	$0.1	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	45	6
12	Edgemoor At20	Transformer	DPL	$0.9	$0.4	$0.0	$0.5	($0.4)	$0.4	($0.1)	($0.9)	($0.4)	36	43
13	Mount Storm - Pruntytown	Line	AP	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.3	455	17
14	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.4	$0.1	($0.0)	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.3	429	270
15	Darley Road - Naamans	Line	DPL	$0.4	$0.2	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	23	0
25	Cecil - Colora	Line	DPL	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	10	1
26	Oak Hall	Transformer	DPL	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	12	0
32	Longwood - Wye Mills	Line	DPL	$0.1	$0.0	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.0	19	3
36	Harrington - S Harrington	Line	DPL	$0.1	$0.0	$0.0	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.0	9	10
44	Easton	Transformer	DPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0

JCPL Control Zone

Table 7-25 JCPL Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-25)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$8.6	$3.1	$0.0	$5.5	$0.0	($0.2)	($0.0)	$0.3	$5.8	806	294
2	Athenia - Saddlebrook	Line	PSEG	($2.1)	($0.6)	($0.0)	($1.6)	($0.1)	$0.0	$0.0	($0.2)	($1.7)	1,779	273
3	East Frankfort - Crete	Line	ComEd	$0.9	$0.3	($0.0)	$0.5	$0.0	($0.0)	$0.0	$0.1	$0.6	835	418
4	West	Interface	500	$0.5	$0.2	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.4	56	37
5	Atlantic - Larrabee	Line	JCPL	$0.2	($0.1)	$0.0	$0.3	$0.0	$0.0	($0.0)	$0.0	$0.3	88	6
6	Sammis - Wylie Ridge	Line	AP	$0.4	$0.2	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.3	305	37
7	Bridgewater - Middlesex	Line	PSEG	$0.1	$0.0	$0.0	$0.0	($0.1)	$0.2	$0.0	($0.3)	($0.2)	25	5
8	Franklin - West Wharton	Line	JCPL	$0.4	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	26	0
9	Bedington - Black Oak	Interface	500	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	519	9
10	AEP-DOM	Interface	500	($0.2)	($0.1)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	452	76
11	Tiltonsville - Windsor	Line	AP	$0.2	$0.1	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	260	139
12	Harrison - Pruntytown	Line	500	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	75	86
13	Branchburg - Readington	Line	PSEG	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	180	0
14	Kilmer - Sayreville	Line	JCPL	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	72	0
15	Crescent	Transformer	DLCO	($0.2)	($0.1)	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.1)	310	58
24	Redoak - Sayreville	Line	JCPL	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	38	0

Table 7-26 JCPL Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-26)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$9.6	$3.9	$0.0	$5.7	$0.0	($0.1)	($0.0)	$0.1	$5.8	380	55
2	5004/5005 Interface	Interface	500	$4.4	$1.7	$0.0	$2.7	$0.1	($0.9)	($0.0)	$0.9	$3.7	256	191
3	Wylie Ridge	Transformer	AP	$3.9	$1.4	$0.0	$2.5	$0.1	($0.6)	($0.0)	$0.7	$3.2	354	335
4	Kammer	Transformer	500	$3.5	$1.2	$0.0	$2.3	($0.0)	($0.3)	($0.0)	$0.2	$2.5	1,021	504
5	Athenia - Saddlebrook	Line	PSEG	($1.3)	($0.3)	($0.0)	($1.0)	($0.0)	$0.1	$0.0	($0.1)	($1.1)	769	108
6	Sammis - Wylie Ridge	Line	AP	$1.4	$0.5	$0.0	$0.9	$0.0	$0.0	($0.0)	$0.0	$0.9	615	101
7	East Frankfort - Crete	Line	ComEd	$0.9	$0.3	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	912	0
8	Cloverdale - Lexington	Line	AEP	$0.8	$0.3	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	571	220
9	Atlantic - Larrabee	Line	JCPL	$0.5	$0.1	$0.0	$0.5	($0.1)	$0.0	($0.0)	($0.1)	$0.4	63	18
10	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.5	$0.1	($0.0)	$0.3	$0.0	($0.0)	$0.0	$0.1	$0.4	429	270
11	Buckingham - Pleasant Valley	Line	PECO	$0.6	$0.2	$0.0	$0.4	($0.0)	($0.1)	($0.0)	$0.0	$0.4	87	30
12	Branchburg - Flagtown	Line	PSEG	$0.8	$0.3	$0.0	$0.5	($0.0)	$0.1	($0.1)	($0.1)	$0.4	161	16
13	AP South	Interface	500	$0.4	$0.1	$0.0	$0.2	($0.0)	($0.0)	($0.0)	$0.0	$0.2	1,088	216
14	Krendale - Seneca	Line	AP	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	158	0
15	Tiltonsville - Windsor	Line	AP	$0.3	$0.2	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	348	87
36	Kilmer - Sayreville	Line	JCPL	$0.4	$0.2	$0.0	$0.2	($0.0)	$0.2	$0.0	($0.2)	$0.0	0	11
42	Atlantic - New Prospect Road	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0

Met-Ed Control Zone

Table 7-27 Met-Ed Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-27)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$5.9	$4.9	$0.0	$1.0	$0.0	($0.4)	($0.0)	$0.4	$1.5	806	294
2	AP South	Interface	500	$2.0	$1.0	($0.0)	$0.9	($0.0)	($0.0)	($0.0)	$0.0	$0.9	1,255	735
3	West	Interface	500	$0.4	$0.2	$0.0	$0.2	$0.0	($0.1)	($0.0)	$0.1	$0.3	56	37
4	Athenia - Saddlebrook	Line	PSEG	($0.7)	($0.6)	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.1)	($0.2)	1,779	273
5	Bedington - Black Oak	Interface	500	$0.6	$0.4	$0.0	$0.2	$0.0	$0.0	($0.0)	$0.0	$0.2	519	9
6	AEP-DOM	Interface	500	$0.1	($0.0)	($0.0)	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	452	76
7	East Frankfort - Crete	Line	ComEd	$0.6	$0.6	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	835	418
8	Sammis - Wylie Ridge	Line	AP	$0.3	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.1	305	37
9	Susquehanna	Transformer	PPL	$0.0	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	36	0
10	Cloverdale - Lexington	Line	AEP	$0.1	$0.1	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	154	94
11	Harrison - Pruntytown	Line	500	$0.1	$0.1	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	75	86
12	Graceton - Raphael Road	Line	BGE	($0.2)	($0.2)	($0.0)	($0.0)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	34	25
13	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.1	$0.1	($0.0)	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	142	3
14	Nipetown - Reid	Line	AP	$0.1	$0.1	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.0	$0.0	75	18
15	Tiltonsville - Windsor	Line	AP	$0.1	$0.2	$0.0	($0.1)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	260	139
32	Collins - Middletown Jct	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	13	0
35	Brunner Island - Yorkana	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
111	Glendon - Hosensack	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

Table 7-28 Met-Ed Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-28)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$1.4	$1.0	$0.0	$0.4	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	1,088	216
2	Wylie Ridge	Transformer	AP	$3.1	$2.8	$0.0	$0.3	($0.1)	($0.2)	($0.0)	$0.0	$0.3	354	335
3	5004/5005 Interface	Interface	500	$2.9	$3.3	$0.0	($0.4)	($0.1)	($0.3)	($0.0)	$0.1	($0.2)	256	191
4	West	Interface	500	$6.9	$6.8	$0.0	$0.1	($0.0)	($0.1)	($0.0)	$0.0	$0.2	380	55
5	Sammis - Wylie Ridge	Line	AP	$1.0	$1.2	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.1)	615	101
6	Cloverdale - Lexington	Line	AEP	$0.7	$0.8	$0.0	($0.1)	($0.0)	($0.0)	($0.0)	$0.0	($0.1)	571	220
7	Bedington	Transformer	AP	$0.1	($0.0)	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.1	236	103
8	Tiltonsville - Windsor	Line	AP	$0.2	$0.4	$0.0	($0.2)	$0.0	($0.0)	$0.0	$0.0	($0.1)	348	87
9	East Frankfort - Crete	Line	ComEd	$0.6	$0.7	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	912	0
10	Middletown Jct	Transformer	Met-Ed	$0.2	($0.0)	$0.0	$0.2	($0.1)	$0.0	($0.0)	($0.1)	$0.1	47	12
11	Bedington - Harmony	Line	AP	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	181	0
12	Krendale - Seneca	Line	AP	$0.2	$0.3	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	158	0
13	Mount Storm - Pruntytown	Line	AP	$0.4	$0.3	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	455	17
14	Conastone	Transformer	BGE	($0.0)	($0.1)	($0.0)	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	8	1
15	Doubs	Transformer	AP	$0.1	$0.0	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	36	13
39	Collins - Middletown Jct	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	4	5
49	Cly - Newberry	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0
73	Gardners - Texas East	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	1
123	Brunner Island - Yorkana	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	1
134	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

PECO Control Zone

Table 7-29 PECO Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-29)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$6.7	$11.6	$0.0	($4.9)	($0.1)	($0.1)	($0.0)	($0.0)	($4.9)	806	294
2	AP South	Interface	500	$0.9	$3.3	$0.0	($2.4)	($0.1)	$0.1	$0.0	($0.1)	($2.5)	1,255	735
3	Bedington - Black Oak	Interface	500	$0.3	$0.9	$0.0	($0.5)	$0.0	$0.0	$0.0	($0.0)	($0.6)	519	9
4	East Frankfort - Crete	Line	ComEd	$0.8	$1.4	$0.0	($0.5)	($0.0)	($0.1)	($0.0)	$0.0	($0.5)	835	418
5	West	Interface	500	$0.5	$1.0	$0.0	($0.5)	($0.0)	($0.1)	$0.0	$0.1	($0.4)	56	37
6	AEP-DOM	Interface	500	($0.2)	$0.1	($0.0)	($0.3)	($0.0)	$0.0	$0.0	($0.0)	($0.3)	452	76
7	Sammis - Wylie Ridge	Line	AP	$0.4	$0.6	$0.0	($0.3)	($0.0)	($0.0)	$0.0	($0.0)	($0.3)	305	37
8	Graceton - Raphael Road	Line	BGE	($0.1)	($0.3)	$0.0	$0.2	$0.1	$0.1	$0.0	($0.0)	$0.2	34	25
9	Athenia - Saddlebrook	Line	PSEG	($0.5)	($1.0)	($0.0)	$0.5	$0.0	$0.3	$0.0	($0.3)	$0.2	1,779	273
10	Harrison - Pruntytown	Line	500	$0.1	$0.1	$0.0	($0.1)	($0.0)	$0.0	$0.0	($0.1)	($0.1)	75	86
11	Burlington - Croydon	Line	PECO	($0.1)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	512	13
12	Crescent	Transformer	DLCO	($0.1)	($0.2)	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	310	58
13	Tiltonsville - Windsor	Line	AEP	$0.1	$0.2	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	437	0
14	Nipetown - Reid	Line	AP	$0.0	$0.1	$0.0	($0.1)	($0.0)	($0.0)	$0.0	($0.0)	($0.1)	75	18
15	Rising	Flowgate	Midwest ISO	$0.1	$0.2	($0.0)	($0.1)	($0.0)	($0.0)	$0.0	$0.0	($0.1)	582	32
25	Cromby	Transformer	PECO	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	33	2
40	Eddystone - Scott Paper	Line	PECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	4
51	Holmesburg - Richmond	Line	PECO	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	49	0
68	Conastone - Peach Bottom	Line	PECO	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
87	Eddystone - Saville	Line	PECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	1

Table 7-30 PECO Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-30)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$3.0	$6.2	$0.0	($3.1)	($0.0)	($0.0)	($0.0)	($0.0)	($3.1)	380	55
2	Kammer	Transformer	500	$0.9	$3.5	$0.0	($2.6)	($0.1)	$0.0	($0.0)	($0.2)	($2.8)	1,021	504
3	AP South	Interface	500	$0.3	$1.8	$0.0	($1.6)	($0.0)	$0.0	$0.0	($0.1)	($1.6)	1,088	216
4	Wylie Ridge	Transformer	AP	$1.3	$2.3	$0.0	($0.9)	($0.1)	$0.0	($0.1)	($0.1)	($1.1)	354	335
5	5004/5005 Interface	Interface	500	$1.9	$2.7	$0.0	($0.9)	$0.0	$0.0	$0.0	($0.0)	($0.9)	256	191
6	Sammis - Wylie Ridge	Line	AP	$0.4	$1.1	$0.0	($0.7)	($0.0)	($0.0)	($0.0)	($0.0)	($0.7)	615	101
7	Cloverdale - Lexington	Line	AEP	$0.3	$0.9	$0.0	($0.6)	($0.0)	($0.0)	$0.0	$0.0	($0.6)	571	220
8	East Frankfort - Crete	Line	ComEd	$0.3	$0.8	($0.0)	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	912	0
9	Mount Storm - Pruntytown	Line	AP	$0.1	$0.5	$0.0	($0.5)	($0.0)	$0.0	$0.0	($0.0)	($0.5)	455	17
10	Conastone	Transformer	BGE	($0.0)	($0.3)	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	8	1
11	Tiltonsville - Windsor	Line	AP	$0.1	$0.4	$0.0	($0.3)	($0.0)	($0.0)	$0.0	$0.0	($0.3)	348	87
12	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.2	$0.4	($0.0)	($0.2)	($0.0)	$0.0	($0.0)	($0.1)	($0.2)	429	270
13	Krendale - Seneca	Line	AP	$0.1	$0.3	$0.0	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	158	0
14	Eddystone - Scott Paper	Line	PECO	$0.2	($0.0)	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	30	2
15	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.0	$0.1	$0.0	($0.1)	($0.1)	($0.0)	($0.0)	($0.0)	($0.2)	62	81
17	Holmesburg - Richmond	Line	PECO	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	$0.0	$0.1	$0.1	13	3
23	Buckingham - Pleasant Valley	Line	PECO	($0.4)	($0.3)	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.0)	($0.1)	87	30
26	Limerick	Transformer	PECO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	21	0
27	Graceton - Peach Bottom	Line	PECO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.1	$0.1	0	13
35	Whitpain	Transformer	PECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0

PENELEC Control Zone

Table 7-31 PENELEC Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-31)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($21.8)	($33.5)	($0.0)	$11.7	$3.2	$0.2	$0.1	$3.0	$14.7	1,255	735
2	5004/5005 Interface	Interface	500	($6.3)	($20.4)	($0.1)	$14.0	$0.8	$0.3	$0.1	$0.5	$14.5	806	294
3	Bedington - Black Oak	Interface	500	($3.7)	($5.8)	($0.0)	$2.0	$0.1	($0.0)	$0.0	$0.1	$2.2	519	9
4	AEP-DOM	Interface	500	($4.4)	($6.3)	($0.0)	$1.8	$0.1	($0.1)	$0.0	$0.2	$2.1	452	76
5	East Frankfort - Crete	Line	ComEd	$2.0	$2.5	$0.0	($0.5)	($0.4)	$0.0	($0.0)	($0.5)	($1.0)	835	418
6	Sammis - Wylie Ridge	Line	AP	$0.3	$1.1	$0.0	($0.8)	($0.1)	($0.1)	($0.0)	($0.0)	($0.8)	305	37
7	West	Interface	500	($0.3)	($0.9)	$0.0	$0.7	$0.2	$0.1	$0.0	$0.1	$0.8	56	37
8	Homer City - Seward	Line	PENELEC	$1.4	$0.8	($0.0)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	37	0
9	Mount Storm - Pruntytown	Line	AP	($0.6)	($1.0)	($0.0)	$0.4	$0.3	$0.2	$0.0	$0.1	$0.4	87	64
10	Seward	Transformer	PENELEC	$0.8	$0.4	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	22	0
11	Altoona - Bear Rock	Line	PENELEC	($0.5)	($0.9)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	16	0
12	Homer City - Johnstown	Line	PENELEC	$0.9	$0.6	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	32	0
13	Homer City	Transformer	PENELEC	$0.7	$0.4	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	80	0
14	Tiltonsville - Windsor	Line	AP	$0.5	$0.5	$0.0	($0.0)	($0.2)	$0.1	($0.0)	($0.2)	($0.3)	260	139
15	Crescent	Transformer	DLCO	($0.6)	($0.7)	($0.0)	$0.1	$0.1	($0.1)	$0.0	$0.1	$0.3	310	58
17	Garrett	Transformer	PENELEC	$1.0	$0.8	$0.0	$0.2	$0.0	$0.1	$0.0	($0.0)	$0.2	102	3
32	Keystone - Shelocta	Line	PENELEC	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	11	0
37	Deepcreek	Transformer	PENELEC	$0.1	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	158	0
40	Homer City - Shelocta	Line	PENELEC	($0.0)	($0.0)	($0.0)	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	1	3
43	Roxbury - Shade Gap	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	0	5

Table 7-32 PENELEC Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-32)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	($2.2)	($15.2)	($0.0)	$13.0	$0.1	$0.1	$0.0	($0.1)	$12.9	380	55
2	AP South	Interface	500	($8.4)	($17.2)	($0.0)	$8.8	$0.6	$0.3	$0.1	$0.4	$9.2	1,088	216
3	Wylie Ridge	Transformer	AP	$1.5	$10.3	$0.1	($8.8)	($0.6)	($0.7)	($0.0)	$0.1	($8.7)	354	335
4	5004/5005 Interface	Interface	500	($1.5)	($8.5)	($0.0)	$7.0	$0.4	$1.5	$0.0	($1.1)	$5.9	256	191
5	Kammer	Transformer	500	$2.2	$7.1	$0.2	($4.7)	($0.1)	($0.2)	($0.1)	$0.0	($4.7)	1,021	504
6	Sammis - Wylie Ridge	Line	AP	$1.0	$3.7	$0.1	($2.6)	($0.1)	($0.1)	$0.0	($0.0)	($2.7)	615	101
7	Mount Storm - Pruntytown	Line	AP	($2.3)	($4.5)	($0.0)	$2.2	$0.3	$0.1	$0.0	$0.3	$2.5	455	17
8	East Frankfort - Crete	Line	ComEd	$1.1	$2.0	$0.0	($0.9)	$0.0	$0.0	$0.0	$0.0	($0.9)	912	0
9	Homer City - Seward	Line	PENELEC	$1.8	$1.1	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	25	0
10	Krendale - Seneca	Line	AP	$0.4	$1.0	$0.0	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.6)	158	0
11	Bedington - Black Oak	Interface	500	($0.5)	($1.0)	($0.0)	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	58	55
12	Altoona - Bear Rock	Line	PENELEC	($0.6)	($1.1)	($0.0)	$0.5	$0.0	($0.0)	$0.0	$0.0	$0.5	30	4
13	Bedington	Transformer	AP	($0.0)	($0.4)	$0.0	$0.4	$0.1	$0.0	$0.0	$0.1	$0.5	236	103
14	Mount Storm	Transformer	AP	($0.5)	($1.1)	($0.0)	$0.5	($0.1)	$0.0	$0.0	($0.1)	$0.5	80	22
15	Tiltonsville - Windsor	Line	AP	$0.3	$0.7	$0.0	($0.4)	$0.0	$0.0	($0.0)	($0.0)	($0.4)	348	87
17	Homer City	Transformer	PENELEC	$0.6	$0.2	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	48	0
18	Seward	Transformer	PENELEC	$0.7	$0.3	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	14	0
20	Altoona - Raystown	Line	PENELEC	($0.6)	($0.9)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	31	0
23	Homer City - Shelocta	Line	PENELEC	($0.4)	($0.5)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	14	0
27	Summit - Westfall	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.0)	($0.1)	($0.1)	0	8

Pepco Control Zone

Table 7-33 Pepco Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-33)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$48.1	$36.3	$0.6	$12.5	($2.2)	($1.6)	($0.8)	($1.5)	$11.0	1,255	735
2	Bedington - Black Oak	Interface	500	$9.6	$6.7	$0.2	$3.1	($0.0)	($0.1)	($0.0)	$0.1	$3.1	519	9
3	AEP-DOM	Interface	500	$8.0	$6.5	$0.1	$1.5	($0.1)	($0.2)	($0.1)	$0.0	$1.5	452	76
4	5004/5005 Interface	Interface	500	$4.3	$3.0	$0.2	$1.5	($0.1)	($0.0)	($0.1)	($0.2)	$1.3	806	294
5	Bowie	Line	Pepco	$2.3	$1.1	$0.1	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	44	0
6	East Frankfort - Crete	Line	ComEd	$2.1	$1.3	$0.0	$0.8	($0.3)	($0.1)	($0.0)	($0.2)	$0.6	835	418
7	Mount Storm - Pruntytown	Line	AP	$1.5	$1.1	$0.0	$0.5	($0.2)	($0.4)	($0.0)	$0.1	$0.6	87	64
8	Benning - Ritchie	Line	Pepco	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	19	0
9	Sammis - Wylie Ridge	Line	AP	$0.9	$0.6	$0.0	$0.3	($0.1)	($0.1)	($0.0)	$0.0	$0.4	305	37
10	Bowie	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.2	$0.4	($0.1)	($0.3)	($0.3)	0	9
11	Harrison - Pruntytown	Line	500	$0.5	$0.4	$0.0	$0.1	($0.2)	($0.3)	($0.0)	$0.1	$0.2	75	86
12	Athenia - Saddlebrook	Line	PSEG	($0.1)	($0.1)	($0.0)	($0.1)	$0.1	($0.0)	$0.2	$0.3	$0.2	1,779	273
13	Burtonsville - Metzerott Rd.	Line	Pepco	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	17	0
14	Doubs	Transformer	AP	$0.5	$0.3	$0.0	$0.2	($0.1)	$0.2	($0.1)	($0.4)	($0.2)	20	33
15	Messic Road - Morgan	Line	AP	$0.6	$0.4	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	172	0
33	Dickerson - Pleasant View	Line	Pepco	$0.1	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	53	3
35	Burches Hill - Talbert	Line	Pepco	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	1	13
55	Buzzard - Ritchie	Line	Pepco	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0

Table 7-34 Pepco Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-34)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$27.3	$21.0	$0.3	$6.6	($0.6)	($1.8)	($0.3)	$0.9	$7.4	1,088	216
2	Kammer	Transformer	500	$9.1	$6.7	$0.1	$2.5	($0.4)	($0.9)	($0.1)	$0.4	$2.9	1,021	504
3	Mount Storm - Pruntytown	Line	AP	$7.4	$5.6	$0.1	$1.8	($0.0)	($0.5)	($0.0)	$0.5	$2.3	455	17
4	West	Interface	500	$8.1	$6.0	$0.0	$2.1	($0.0)	($0.1)	($0.0)	$0.0	$2.2	380	55
5	Wylie Ridge	Transformer	AP	$6.2	$4.9	$0.0	$1.3	($0.3)	($0.7)	($0.0)	$0.3	$1.7	354	335
6	Cloverdale - Lexington	Line	AEP	$4.8	$3.6	$0.1	$1.3	($0.1)	($0.3)	($0.1)	$0.1	$1.4	571	220
7	Sammis - Wylie Ridge	Line	AP	$2.4	$1.6	$0.0	$0.8	($0.1)	($0.1)	($0.0)	($0.0)	$0.8	615	101
8	Bedington - Black Oak	Interface	500	$1.7	$1.2	$0.0	$0.5	$0.0	($0.1)	($0.0)	$0.1	$0.6	58	55
9	East Frankfort - Crete	Line	ComEd	$1.6	$1.1	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	912	0
10	Mount Storm	Transformer	AP	$1.5	$1.1	$0.0	$0.4	($0.0)	($0.1)	($0.0)	$0.0	$0.5	80	22
11	5004/5005 Interface	Interface	500	$1.0	$0.7	$0.0	$0.3	($0.0)	($0.1)	($0.0)	$0.1	$0.4	256	191
12	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.9	$0.6	($0.0)	$0.2	($0.1)	($0.2)	($0.0)	$0.1	$0.3	429	270
13	Tiltonsville - Windsor	Line	AP	$0.7	$0.5	$0.0	$0.2	($0.0)	($0.1)	($0.0)	$0.0	$0.2	348	87
14	Dickerson - Pleasant View	Line	Pepco	$0.5	$0.3	$0.0	$0.2	($0.0)	($0.0)	($0.0)	$0.0	$0.2	15	13
15	AEP-DOM	Interface	500	$0.7	$0.5	$0.0	$0.2	($0.0)	($0.1)	($0.1)	($0.0)	$0.2	96	56
21	Brighton	Transformer	Pepco	$0.2	$0.1	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	6	1
58	Pumphrey - Westport	Line	Pepco	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	253	0
126	Burches Hill	Transformer	Pepco	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	1

PPL Control Zone

Table 7-35 PPL Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-35)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$19.2	$24.2	$0.5	($4.6)	$0.3	$0.3	($0.2)	($0.1)	($4.7)	806	294
2	Susquehanna	Transformer	PPL	$1.0	$0.3	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	36	0
3	AP South	Interface	500	$1.1	$0.7	$0.2	$0.5	$0.1	($0.1)	($0.1)	$0.1	$0.6	1,255	735
4	East Frankfort - Crete	Line	ComEd	$1.6	$2.1	$0.0	($0.5)	$0.1	$0.0	($0.0)	$0.1	($0.3)	835	418
5	Sammis - Wylie Ridge	Line	AP	$0.8	$1.0	$0.0	($0.2)	($0.0)	$0.0	($0.0)	($0.0)	($0.3)	305	37
6	West	Interface	500	$1.1	$1.3	$0.0	($0.1)	($0.0)	$0.1	($0.0)	($0.1)	($0.2)	56	37
7	Bedington - Black Oak	Interface	500	$0.5	$0.4	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.2	519	9
8	Hawthorn - Waldwick	Line	PSEG	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	454	36
9	Baker - Broadford	Line	AEP	($0.0)	($0.0)	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	10	74
10	Tiltonsville - Windsor	Line	AP	$0.3	$0.4	$0.0	($0.1)	$0.1	$0.0	($0.0)	$0.0	($0.1)	260	139
11	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.3	$0.3	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	142	3
12	Athenia - Saddlebrook	Line	PSEG	($1.8)	($2.0)	($0.0)	$0.1	($0.1)	$0.1	$0.1	($0.1)	$0.1	1,779	273
13	Rising	Flowgate	Midwest ISO	$0.2	$0.3	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)	582	32
14	Crescent	Transformer	DLCO	($0.3)	($0.4)	($0.0)	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.0	310	58
15	Tiltonsville - Windsor	Line	AEP	$0.2	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	437	0
36	Wescosville	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0

Table 7-36 PPL Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-36)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$0.5	$1.6	$0.3	($0.7)	($0.0)	($0.0)	($0.2)	($0.2)	($0.9)	1,021	504
2	AP South	Interface	500	$0.4	($0.2)	$0.1	$0.7	($0.0)	($0.0)	$0.1	$0.1	$0.8	1,088	216
3	West	Interface	500	$2.8	$4.1	$0.5	($0.8)	($0.0)	($0.1)	($0.0)	$0.1	($0.7)	380	55
4	Sammis - Wylie Ridge	Line	AP	$0.1	$0.7	$0.1	($0.5)	$0.0	($0.0)	$0.0	$0.1	($0.4)	615	101
5	5004/5005 Interface	Interface	500	$1.3	$2.2	$0.3	($0.5)	$0.1	($0.8)	($0.1)	$0.8	$0.3	256	191
6	Wylie Ridge	Transformer	AP	$1.1	$1.8	$0.3	($0.4)	$0.2	$0.1	$0.0	$0.1	($0.3)	354	335
7	Mount Storm - Pruntytown	Line	AP	$0.1	($0.1)	$0.0	$0.3	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	455	17
8	East Frankfort - Crete	Line	ComEd	$0.1	$0.4	$0.0	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	912	0
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.1	$0.3	($0.0)	($0.2)	($0.0)	($0.0)	$0.0	($0.0)	($0.2)	429	270
10	Cloverdale - Lexington	Line	AEP	$0.1	$0.3	$0.1	($0.1)	($0.0)	($0.0)	$0.0	$0.0	($0.1)	571	220
11	Buckingham - Pleasant Valley	Line	PECO	$0.0	$0.1	$0.0	($0.1)	($0.0)	($0.0)	($0.0)	$0.0	($0.1)	87	30
12	Mount Storm	Transformer	AP	$0.0	($0.0)	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	80	22
13	Bedington - Black Oak	Interface	500	$0.0	($0.0)	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	58	55
14	Cedar Grove - Roseland	Line	PSEG	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	29	56
15	Krendale - Seneca	Line	AP	$0.1	$0.1	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	158	0

PSEG Control Zone

Table 7-37 PSEG Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-37)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Hawthorn - Waldwick	Line	PSEG	$0.1	($0.0)	($0.0)	$0.0	($0.7)	$1.1	($1.6)	($3.4)	($3.4)	454	36
2	AP South	Interface	500	$0.2	$2.3	$1.1	($1.1)	$0.1	($0.2)	($0.9)	($0.6)	($1.7)	1,255	735
3	Hawthorn - Hinchmans Ave	Line	PSEG	($0.0)	($0.0)	($0.2)	($0.2)	($0.1)	$0.4	($0.9)	($1.4)	($1.6)	209	35
4	5004/5005 Interface	Interface	500	$11.9	$12.5	$1.2	$0.6	($0.2)	$0.7	($0.5)	($1.4)	($0.8)	806	294
5	Bayonne - PVSC	Line	PSEG	$0.0	($0.4)	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	507	0
6	Branchburg - Readington	Line	PSEG	$0.5	$0.0	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	180	0
7	Hudson - Marion	Line	PSEG	$0.3	$0.1	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	170	0
8	Graceton - Raphael Road	Line	BGE	($0.3)	($0.4)	($0.0)	$0.0	$0.2	($0.1)	$0.1	$0.4	$0.4	34	25
9	East Frankfort - Crete	Line	ComEd	$1.3	$1.4	$0.0	($0.0)	($0.1)	$0.2	($0.1)	($0.3)	($0.4)	835	418
10	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($0.0)	($0.0)	$0.1	$0.1	($0.0)	$0.0	($0.5)	($0.5)	($0.4)	556	21
11	Athenia - Saddlebrook	Line	PSEG	$9.3	$1.2	$5.3	$13.4	($6.5)	$2.7	($4.6)	($13.7)	($0.4)	1,779	273
12	West	Interface	500	$0.8	$0.8	$0.1	$0.1	($0.1)	$0.1	($0.1)	($0.4)	($0.4)	56	37
13	Bedington - Black Oak	Interface	500	$0.3	$0.8	$0.3	($0.3)	$0.0	($0.0)	($0.0)	($0.0)	($0.3)	519	9
14	Atlantic - Larrabee	Line	JCPL	$0.1	($0.1)	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	88	6
15	Tiltonsville - Windsor	Line	AP	$0.3	$0.3	$0.0	$0.1	($0.1)	$0.0	($0.2)	($0.2)	($0.2)	260	139
16	Fairlawn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	($0.2)	0	4
17	Fairlawn - Saddlebrook	Line	PSEG	$0.2	$0.1	$0.3	$0.4	($0.0)	$0.1	($0.4)	($0.5)	($0.2)	209	16
18	Hudson	Transformer	PSEG	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	30	0
19	Bayway - Federal Square	Line	PSEG	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	109	1
21	Linden - North Ave	Line	PSEG	$0.1	($0.1)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	66	1

Table 7-38 PSEG Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-38)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Athenia - Saddlebrook	Line	PSEG	$3.0	$0.5	$1.2	$3.7	($0.3)	$0.1	($0.5)	($0.9)	$2.8	769	108
2	Plainsboro - Trenton	Line	PSEG	$2.4	($0.1)	$0.1	$2.6	($0.2)	$0.3	($0.1)	($0.6)	$2.0	275	113
3	Wylie Ridge	Transformer	AP	$4.3	$5.4	$0.5	($0.6)	$0.0	$0.1	($0.6)	($0.7)	($1.3)	354	335
4	AP South	Interface	500	$0.4	$2.1	$0.6	($1.1)	$0.0	($0.1)	($0.2)	($0.2)	($1.2)	1,088	216
5	West	Interface	500	$10.8	$12.7	$0.8	($1.1)	($0.0)	$0.0	($0.1)	($0.2)	($1.2)	380	55
6	Fairlawn - Saddlebrook	Line	PSEG	$0.8	$0.1	$0.4	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	506	0
7	Leonia - New Milford	Line	PSEG	$0.5	$0.1	$0.7	$1.1	($0.0)	$0.0	($0.1)	($0.1)	$1.0	632	14
8	5004/5005 Interface	Interface	500	$5.1	$5.0	$0.3	$0.4	$0.0	$0.8	($0.4)	($1.2)	($0.8)	256	191
9	Buckingham - Pleasant Valley	Line	PECO	$0.7	($0.1)	$0.0	$0.9	($0.0)	$0.1	($0.0)	($0.2)	$0.7	87	30
10	Branchburg - Flagtown	Line	PSEG	$0.6	($0.0)	$0.1	$0.7	($0.0)	$0.1	($0.1)	($0.2)	$0.4	161	16
11	Bayway - Federal Square	Line	PSEG	$0.3	($0.1)	$0.0	$0.4	($0.0)	($0.0)	($0.0)	$0.0	$0.4	63	9
12	Cedar Grove - Roseland	Line	PSEG	$0.3	$0.0	$0.0	$0.3	($0.1)	$0.4	($0.2)	($0.7)	($0.4)	29	56
13	Mount Storm - Pruntytown	Line	AP	$0.0	$0.5	$0.1	($0.3)	$0.0	($0.0)	($0.1)	($0.0)	($0.4)	455	17
14	Kammer	Transformer	500	$4.4	$4.4	$0.3	$0.3	($0.1)	$0.3	($0.3)	($0.6)	($0.3)	1,021	504
15	Cloverdale - Lexington	Line	AEP	$1.0	$1.2	$0.1	($0.1)	$0.0	$0.1	($0.1)	($0.2)	($0.3)	571	220
17	Sewaren	Transformer	PSEG	$0.1	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	42	0
18	Bayonne - PVSC	Line	PSEG	$0.0	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	102	0
19	Fairlawn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.1)	($0.1)	($0.1)	0	18
21	Brunswick - Edison	Line	PSEG	$0.2	($0.0)	$0.0	$0.3	($0.1)	$0.2	($0.1)	($0.4)	($0.1)	41	59
24	Bergen - Saddlebrook	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	111	0

RECO Control Zone

Table 7-39 RECO Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-39)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$0.4	$0.1	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.4	806	294
2	Athenia - Saddlebrook	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.1	$0.2	1,779	273
3	AP South	Interface	500	($0.1)	($0.0)	$0.0	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	1,255	735
4	Hawthorn - Hinchmans Ave	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	209	35
5	Hawthorn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	454	36
6	East Frankfort - Crete	Line	ComEd	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	835	418
7	West	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	56	37
8	Fairlawn - Saddlebrook	Line	PSEG	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	209	16
9	Tiltonsville - Windsor	Line	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	260	139
10	AEP-DOM	Interface	500	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	452	76
11	Crescent	Transformer	DLCO	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	310	58
12	Graceton - Raphael Road	Line	BGE	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	34	25
13	Fairlawn - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	4
14	Doubs	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	20	33
15	Sammis - Wylie Ridge	Line	AP	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	305	37

Table 7-40 RECO Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-40)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	380	55
2	5004/5005 Interface	Interface	500	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.1)	$0.2	256	191
3	Kammer	Transformer	500	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	1,021	504
4	Wylie Ridge	Transformer	AP	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	354	335
5	Athenia - Saddlebrook	Line	PSEG	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	$0.0	($0.0)	$0.1	769	108
6	Sammis - Wylie Ridge	Line	AP	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	615	101
7	AP South	Interface	500	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	1,088	216
8	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	912	0
9	Fairlawn - Saddlebrook	Line	PSEG	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	506	0
10	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	429	270
11	Cloverdale - Lexington	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	571	220
12	Krendale - Seneca	Line	AP	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	158	0
13	Mount Storm - Pruntytown	Line	AP	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	455	17
14	Tiltonsville - Windsor	Line	AP	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	348	87
15	Plainsboro - Trenton	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	275	113

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-41 AEP Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-41)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AEP-DOM	Interface	500	$7.5	($20.0)	$0.9	$28.4	($0.1)	($0.3)	$0.0	$0.3	$28.7	452	76
2	AP South	Interface	500	($13.8)	($37.5)	$0.2	$23.9	($3.1)	$1.3	$0.6	($3.8)	$20.1	1,255	735
3	Baker - Broadford	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($1.5)	$1.0	($3.5)	($5.9)	($5.6)	10	74
4	5004/5005 Interface	Interface	500	($9.0)	($14.1)	($0.2)	$4.9	($0.6)	$0.8	$0.2	($1.2)	$3.7	806	294
5	Bedington - Black Oak	Interface	500	($2.9)	($6.1)	($0.0)	$3.2	($0.1)	($0.1)	$0.0	$0.0	$3.2	519	9
6	Kanawha River	Transformer	AEP	$2.1	($0.2)	$0.3	$2.6	$0.0	($0.0)	($0.0)	$0.0	$2.6	158	11
7	Kanawha - Kincaid	Line	AEP	$1.4	($0.7)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	207	0
8	Culloden - Wyoming	Line	AEP	$0.6	($0.8)	$0.5	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	46	0
9	Sullivan	Transformer	AEP	($0.0)	($1.0)	($0.0)	$1.0	$0.0	$0.0	$0.0	($0.0)	$0.9	154	35
10	Mount Storm - Pruntytown	Line	AP	($0.4)	($1.2)	$0.0	$0.8	($0.2)	$0.1	$0.0	($0.3)	$0.5	87	64
11	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	$0.0	$0.4	$0.4	$0.0	($0.0)	($0.9)	($0.9)	($0.5)	556	21
12	East Frankfort - Crete	Line	ComEd	$2.6	$2.3	$0.4	$0.7	$0.1	($0.1)	($0.5)	($0.2)	$0.4	835	418
13	Rising	Flowgate	Midwest ISO	$0.3	$0.7	$0.0	($0.4)	$0.0	($0.0)	($0.0)	($0.0)	($0.4)	582	32
14	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.7	$0.4	($0.0)	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	142	3
15	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.1)	($0.0)	($0.3)	($0.3)	0	48
16	Ruth - Turner	Line	AEP	$0.1	($0.2)	$0.0	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	18	11
17	Cloverdale - Lexington	Line	AEP	($0.8)	($0.8)	($0.0)	$0.0	($0.0)	$0.3	$0.1	($0.3)	($0.3)	154	94
19	Kammer	Transformer	AEP	$0.1	($0.2)	$0.0	$0.3	$0.0	$0.1	($0.0)	($0.1)	$0.2	33	11
26	Sporn - Kyger Creek	Line	AEP	($0.0)	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	31	0
30	Tiltonsville - Windsor	Line	AEP	($0.4)	($0.6)	($0.1)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	437	0

Table 7-42 AEP Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-42)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($11.3)	($18.9)	$0.8	$8.4	($0.3)	$0.2	$0.1	($0.3)	$8.2	1,088	216
2	Ruth - Turner	Line	AEP	$4.3	($1.5)	$0.5	$6.3	($1.2)	($0.4)	($0.1)	($0.9)	$5.4	514	245
3	Kanawha - Kincaid	Line	AEP	$2.8	($2.1)	$0.2	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	291	0
4	Kammer - Ormet	Line	AEP	$7.7	$1.2	$0.3	$6.8	($1.6)	$0.5	($0.1)	($2.2)	$4.6	514	509
5	Kanawha River	Transformer	AEP	$3.2	($0.3)	$0.5	$4.0	$0.1	($0.3)	($0.1)	$0.4	$4.3	159	37
6	Kammer	Transformer	500	($8.8)	($13.8)	($0.2)	$4.8	($0.3)	$1.0	$0.5	($0.9)	$3.9	1,021	504
7	Kanawha River - Bradley	Line	AEP	$1.3	($2.2)	$0.2	$3.8	($0.0)	$0.1	$0.0	($0.1)	$3.7	24	15
8	Sammis - Wylie Ridge	Line	AP	($4.3)	($2.3)	($0.1)	($2.1)	($0.2)	$0.1	($0.0)	($0.4)	($2.5)	615	101
9	Mount Storm - Pruntytown	Line	AP	($3.0)	($5.0)	$0.2	$2.2	$0.2	$0.0	$0.0	$0.2	$2.4	455	17
10	Breed - Wheatland	Line	AEP	$0.1	($2.4)	($0.3)	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	245	0
11	East Frankfort - Crete	Line	ComEd	$2.4	$1.5	$1.1	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	912	0
12	Cloverdale - Lexington	Line	AEP	($5.7)	($4.0)	($0.3)	($2.0)	$0.4	$0.2	$0.1	$0.3	($1.8)	571	220
13	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.6	$0.2	$0.2	$0.5	($0.1)	$0.0	($1.8)	($1.9)	($1.4)	62	81
14	AEP-DOM	Interface	500	$0.4	($1.2)	$0.1	$1.7	($0.2)	$0.4	($0.0)	($0.6)	$1.1	96	56
15	Wylie Ridge	Transformer	AP	($7.9)	($8.2)	$0.6	$0.9	$0.7	$0.5	($0.1)	$0.2	$1.0	354	335
25	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.3	($0.1)	$0.1	$0.5	$0.5	0	99
28	Kammer	Transformer	AEP	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.1	($0.0)	($0.1)	$0.3	59	13
36	Sullivan	Transformer	AEP	($0.0)	($0.2)	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	9	2
45	Olive - Green Acre	Line	AEP	$0.1	$0.0	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	20	0
51	Breed - Sullivan	Line	AEP	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	10	0

AP Control Zone

Table 7-43 AP Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-43)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($13.2)	($53.0)	($4.2)	$35.6	$2.0	$2.1	$4.5	$4.5	$40.1	1,255	735
2	Bedington - Black Oak	Interface	500	($2.0)	($8.6)	($0.2)	$6.3	$0.3	($0.1)	$0.1	$0.4	$6.7	519	9
3	AEP-DOM	Interface	500	($2.1)	($7.8)	$0.3	$6.0	$0.2	($0.2)	($0.1)	$0.4	$6.4	452	76
4	5004/5005 Interface	Interface	500	($8.9)	($13.0)	($0.6)	$3.6	$0.4	$0.7	$0.4	$0.2	$3.7	806	294
5	Mount Storm - Pruntytown	Line	AP	($0.3)	($1.6)	($0.0)	$1.3	$0.2	($0.2)	$0.1	$0.4	$1.7	87	64
6	Tiltonsville - Windsor	Line	AEP	$0.9	$0.1	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	437	0
7	Harrisonburg - Endless Caverns	Line	Dominion	$0.7	$0.1	$0.2	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	128	0
8	Albright - Snowy Creek	Line	AP	$0.6	($0.1)	$0.0	$0.7	$0.0	($0.0)	($0.0)	$0.0	$0.7	226	2
9	Pruntytown	Transformer	AP	$0.6	($0.1)	($0.0)	$0.7	($0.1)	($0.1)	$0.1	$0.1	$0.7	62	21
10	Tiltonsville - Windsor	Line	AP	$1.4	$0.5	$0.1	$1.0	($0.3)	($0.1)	($0.3)	($0.5)	$0.5	260	139
11	Pleasant Prairie - Zion	Flowgate	Midwest ISO	($0.0)	($0.0)	$0.2	$0.2	$0.0	($0.0)	($0.7)	($0.7)	($0.5)	556	21
12	Nipetown - Reid	Line	AP	($0.0)	($0.5)	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	75	18
13	Endless Caverns	Transformer	Dominion	$0.4	$0.1	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	75	0
14	Dutch Fork - Windsor	Line	AP	$0.4	$0.1	$0.1	$0.4	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	119	3
15	Hamilton - Weirton	Line	AP	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	86	12
18	Messic Road - Morgan	Line	AP	($0.3)	($0.6)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	172	0
20	Kingwood - Pruntytown	Line	AP	$0.2	($0.0)	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.3	62	9
22	Middlebourne - Willow	Line	AP	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	58	0
23	Bedington - Shepherdstown	Line	AP	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	68	0
24	New Martinsville - Paden City	Line	AP	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	($0.1)	($0.2)	($0.2)	23	26

Table 7-44 AP Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-44)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($8.2)	($35.4)	($3.1)	$24.1	$1.3	$0.6	$2.3	$3.0	$27.1	1,088	216
2	Mount Storm - Pruntytown	Line	AP	($2.0)	($9.9)	($0.6)	$7.3	$0.4	$0.2	$0.5	$0.7	$8.0	455	17
3	Wylie Ridge	Transformer	AP	$6.1	$7.4	$5.4	$4.1	($1.1)	($0.5)	($7.2)	($7.7)	($3.6)	354	335
4	Kammer	Transformer	500	$8.3	$11.9	$4.2	$0.5	($1.0)	($1.7)	($4.6)	($3.9)	($3.4)	1,021	504
5	5004/5005 Interface	Interface	500	($4.5)	($6.6)	($0.6)	$1.5	$0.8	$0.7	$1.6	$1.7	$3.2	256	191
6	Bedington - Harmony	Line	AP	$1.7	($0.1)	$0.4	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	181	0
7	Cloverdale - Lexington	Line	AEP	$1.1	($1.2)	$0.7	$3.1	($0.2)	$0.0	($0.8)	($1.0)	$2.1	571	220
8	Doubs	Transformer	AP	$1.5	($0.0)	$0.0	$1.5	$0.0	$0.0	($0.1)	($0.1)	$1.4	36	13
9	Bedington	Transformer	AP	$4.1	($0.3)	$0.1	$4.4	($3.8)	($0.2)	($2.3)	($5.8)	($1.4)	236	103
10	Bedington - Black Oak	Interface	500	($0.4)	($2.0)	($0.1)	$1.5	($0.3)	$0.2	$0.4	($0.2)	$1.4	58	55
11	West	Interface	500	($12.5)	($15.2)	($2.0)	$0.8	$0.2	$0.1	$0.2	$0.3	$1.1	380	55
12	Sammis - Wylie Ridge	Line	AP	$3.0	$2.3	$1.5	$2.2	($0.2)	($0.2)	($1.0)	($1.1)	$1.1	615	101
13	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.3	$0.2	$0.1	$0.2	($0.2)	($0.1)	($1.0)	($1.1)	($0.9)	62	81
14	Tiltonsville - Windsor	Line	AP	$1.9	$0.5	$0.2	$1.6	($0.3)	($0.1)	($0.5)	($0.7)	$0.9	348	87
15	Mount Storm	Transformer	AP	($0.3)	($1.6)	($0.2)	$1.0	$0.0	$0.3	$0.1	($0.1)	$0.8	80	22
17	Krendale - Seneca	Line	AP	$0.6	$0.1	$0.1	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	158	0
21	Hamilton - Weirton	Line	AP	$0.6	$0.1	$0.1	$0.6	($0.0)	($0.1)	($0.2)	($0.0)	$0.5	134	15
23	Kingwood - Pruntytown	Line	AP	$0.3	($0.0)	$0.0	$0.3	($0.0)	$0.0	$0.0	$0.0	$0.3	38	1
24	Inwood - Stonewall	Line	AP	$0.3	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	39	0
25	Middlebourne - Willow	Line	AP	$0.5	$0.1	$0.0	$0.4	($0.0)	($0.0)	($0.0)	($0.1)	$0.3	53	12

ComEd Control Zone

Table 7-45 ComEd Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-45)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($28.8)	($44.4)	($0.3)	$15.4	($0.6)	$0.6	$0.0	($1.3)	$14.1	1,255	735
2	East Frankfort - Crete	Line	ComEd	($13.3)	($26.2)	($0.6)	$12.3	($1.9)	$0.7	$0.0	($2.5)	$9.8	835	418
3	5004/5005 Interface	Interface	500	($12.0)	($18.9)	($0.0)	$6.8	($0.2)	($0.1)	($0.0)	($0.2)	$6.7	806	294
4	AEP-DOM	Interface	500	($10.4)	($16.4)	($0.4)	$5.6	($0.1)	($0.2)	($0.0)	$0.1	$5.7	452	76
5	Rising	Flowgate	Midwest ISO	($2.0)	($6.0)	($0.0)	$3.9	($0.0)	($0.0)	$0.0	$0.0	$3.9	582	32
6	Bedington - Black Oak	Interface	500	($4.9)	($8.2)	($0.0)	$3.2	($0.0)	($0.0)	($0.0)	($0.0)	$3.2	519	9
7	Waterman - West Dekalb	Line	ComEd	($0.4)	($2.3)	$0.1	$1.9	$0.2	$0.2	($0.0)	($0.0)	$1.9	812	159
8	Dunes Acres - Michigan City	Flowgate	Midwest ISO	($2.4)	($3.6)	($0.1)	$1.1	($0.0)	($0.0)	$0.0	$0.0	$1.1	142	3
9	Pleasant Valley - Belvidere	Line	ComEd	($0.7)	($2.8)	$0.1	$2.2	($0.1)	$0.8	($0.3)	($1.2)	$1.0	274	68
10	Sammis - Wylie Ridge	Line	AP	($1.1)	($1.9)	($0.0)	$0.8	($0.0)	$0.0	$0.0	($0.1)	$0.7	305	37
11	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.6	($0.0)	($0.7)	($0.7)	0	82
12	Glidden - West Dekalb	Line	ComEd	($0.0)	($0.6)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	108	0
13	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.2	($2.7)	$0.6	$3.5	$0.3	$0.8	($2.4)	($2.9)	$0.6	556	21
14	Tiltonsville - Windsor	Line	AP	($0.9)	($1.5)	($0.0)	$0.5	($0.0)	($0.0)	$0.0	$0.0	$0.5	260	139
15	Davis	Transformer	ComEd	$0.1	($0.4)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	55	0
26	Wilton Center	Transformer	ComEd	($0.3)	($0.4)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	23	6
32	Belvidere - Woodstock	Line	ComEd	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	7	0
37	Waukegan - Zion	Line	ComEd	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	12	0
50	Silver Lake	Transformer	ComEd	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	17	0
58	Powerton	Line	ComEd	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	23	0

Table 7-46 ComEd Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-46)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	East Frankfort - Crete	Line	ComEd	($10.1)	($20.0)	($0.0)	$9.8	$0.0	$0.0	$0.0	$0.0	$9.8	912	0
2	AP South	Interface	500	($14.8)	($23.5)	($0.0)	$8.7	($0.8)	($0.4)	($0.0)	($0.4)	$8.2	1,088	216
3	Pleasant Valley - Belvidere	Line	ComEd	($1.0)	($7.9)	$0.0	$6.9	$0.7	$0.3	($0.0)	$0.4	$7.4	477	78
4	Kammer	Transformer	500	($11.0)	($18.7)	($0.0)	$7.7	($0.8)	($0.1)	($0.1)	($0.8)	$7.0	1,021	504
5	Wylie Ridge	Transformer	AP	($7.9)	($10.9)	($0.0)	$3.0	($0.8)	($1.5)	$0.0	$0.8	$3.8	354	335
6	West	Interface	500	($11.3)	($14.9)	($0.0)	$3.5	($0.0)	($0.0)	($0.0)	($0.0)	$3.5	380	55
7	Glidden - West Dekalb	Line	ComEd	($0.2)	($3.4)	$0.0	$3.3	$0.0	$0.0	$0.0	$0.0	$3.3	582	0
8	Mount Storm - Pruntytown	Line	AP	($4.0)	($6.6)	($0.0)	$2.6	($0.1)	($0.3)	($0.0)	$0.2	$2.9	455	17
9	Cloverdale - Lexington	Line	AEP	($4.0)	($7.0)	$0.0	$3.0	($0.5)	($0.3)	($0.0)	($0.2)	$2.7	571	220
10	5004/5005 Interface	Interface	500	($4.6)	($6.9)	($0.0)	$2.4	($0.6)	($0.9)	($0.0)	$0.3	$2.6	256	191
11	Sliver Lake - Cherry Valley	Line	ComEd	$0.0	($2.3)	$0.1	$2.4	$0.0	$0.0	($0.0)	($0.0)	$2.3	215	3
12	Cherry Valley	Transformer	ComEd	$0.2	($2.0)	$0.0	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	14	0
13	Sammis - Wylie Ridge	Line	AP	($3.0)	($5.4)	($0.0)	$2.4	($0.2)	($0.1)	($0.0)	($0.1)	$2.2	615	101
14	Electric Jct - Nelson	Line	ComEd	$0.0	($1.5)	$0.1	$1.5	$1.5	$0.9	($0.1)	$0.5	$2.0	183	104
15	Dunes Acres - Michigan City	Flowgate	Midwest ISO	($6.8)	($10.8)	($0.0)	$3.9	($2.2)	($0.5)	($0.3)	($2.0)	$2.0	429	270
16	Quad Cities - Cordova	Line	ComEd	$0.2	($1.0)	$0.0	$1.3	($0.0)	$0.1	$0.0	($0.1)	$1.2	97	15
18	Kincaid - Pana North	Line	ComEd	($0.4)	($1.5)	($0.0)	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	281	0
19	Burnham - Munster	Line	ComEd	($1.7)	($2.8)	($0.0)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	107	0
27	Waterman - West Dekalb	Line	ComEd	($0.1)	($0.6)	$0.0	$0.5	$0.1	($0.0)	($0.0)	$0.1	$0.5	424	9
35	Paddock	Transformer	ComEd	($0.0)	($0.3)	($0.0)	$0.3	$0.1	$0.2	$0.1	$0.0	$0.3	21	77

DAY Control Zone

Table 7-47 DAY Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-47)

				Congestion Costs (Millions)									Event Hours	
				Day Ahead				Balancing						
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($1.7)	($2.9)	($0.1)	$1.1	($0.0)	$0.2	$0.1	($0.2)	$0.9	1,255	735
2	5004/5005 Interface	Interface	500	($0.6)	($1.4)	($0.0)	$0.8	$0.0	$0.1	$0.0	($0.1)	$0.7	806	294
3	AEP-DOM	Interface	500	($0.7)	($1.4)	($0.0)	$0.7	($0.0)	($0.0)	$0.0	$0.0	$0.7	452	76
4	Bedington - Black Oak	Interface	500	($0.3)	($0.6)	($0.0)	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	519	9
5	East Frankfort - Crete	Line	ComEd	$0.1	$0.3	$0.0	($0.2)	$0.0	$0.0	($0.0)	($0.0)	($0.2)	835	418
6	Sporn - Kyger Creek	Line	AEP	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	31	0
7	Kanawha River	Transformer	AEP	($0.1)	($0.1)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	158	11
8	Rising	Flowgate	Midwest ISO	$0.0	$0.1	($0.0)	($0.1)	$0.0	($0.0)	($0.0)	($0.0)	($0.1)	582	32
9	Tiltonsville - Windsor	Line	AP	($0.1)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.1	260	139
10	Baker - Broadford	Line	AEP	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.0	($0.1)	($0.1)	10	74
11	Cloverdale - Lexington	Line	AEP	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.1	154	94
12	Sammis - Wylie Ridge	Line	AP	($0.1)	($0.1)	($0.0)	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	305	37
13	Kanawha - Kincaid	Line	AEP	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	207	0
14	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	142	3
15	Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	556	21

Table 7-48 DAY Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-48)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	($0.8)	($1.9)	($0.0)	$1.0	$0.2	$0.2	$0.0	$0.0	$1.1	1,021	504
2	West	Interface	500	($0.8)	($1.4)	$0.0	$0.7	$0.0	$0.0	($0.0)	$0.0	$0.7	380	55
3	AP South	Interface	500	($1.3)	($1.9)	$0.0	$0.6	$0.1	$0.1	($0.0)	($0.1)	$0.5	1,088	216
4	Wylie Ridge	Transformer	AP	($0.6)	($1.1)	($0.0)	$0.5	$0.2	$0.2	$0.0	($0.0)	$0.4	354	335
5	Cloverdale - Lexington	Line	AEP	($0.3)	($0.7)	$0.0	$0.5	$0.0	$0.1	$0.0	($0.1)	$0.4	571	220
6	Sammis - Wylie Ridge	Line	AP	($0.2)	($0.4)	($0.0)	$0.2	$0.0	$0.1	($0.0)	($0.0)	$0.2	615	101
7	Pierce - Foster	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.2)	($0.2)	0	4
8	Kammer - Ormet	Line	AEP	($0.1)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	514	509
9	Mount Storm	Transformer	AP	($0.0)	($0.1)	($0.0)	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	80	22
10	5004/5005 Interface	Interface	500	($0.4)	($0.5)	$0.0	$0.1	$0.1	$0.1	($0.0)	($0.0)	$0.1	256	191
11	Kanawha River	Transformer	AEP	($0.1)	($0.2)	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	159	37
12	AEP-DOM	Interface	500	($0.1)	($0.1)	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	96	56
13	Breed - Wheatland	Line	AEP	$0.0	$0.1	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	245	0
14	East Frankfort - Crete	Line	ComEd	$0.1	$0.2	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	912	0
15	Kanawha - Kincaid	Line	AEP	($0.1)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	291	0

DLCO Control Zone

Table 7-49 DLCO Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-49)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crescent	Transformer	DLCO	$5.2	$0.0	$0.1	$5.3	($0.0)	($0.5)	($0.2)	$0.3	$5.6	310	58
2	AP South	Interface	500	($19.5)	($24.6)	($0.1)	$5.0	($0.8)	($0.1)	$0.2	($0.6)	$4.4	1,255	735
3	Collier - Elwyn	Line	DLCO	$1.9	$0.3	$0.1	$1.7	($0.0)	($0.1)	($0.0)	$0.0	$1.7	165	25
4	5004/5005 Interface	Interface	500	($6.5)	($8.0)	($0.1)	$1.5	($0.2)	($0.1)	$0.0	($0.1)	$1.4	806	294
5	AEP-DOM	Interface	500	($4.3)	($5.7)	($0.0)	$1.4	($0.2)	($0.1)	$0.0	($0.1)	$1.3	452	76
6	Bedington - Black Oak	Interface	500	($3.0)	($4.0)	($0.0)	$0.9	($0.1)	($0.1)	$0.0	($0.0)	$0.8	519	9
7	Sammis - Wylie Ridge	Line	AP	($1.3)	($2.1)	($0.0)	$0.8	($0.1)	$0.1	$0.0	($0.2)	$0.6	305	37
8	East Frankfort - Crete	Line	ComEd	$0.6	$0.9	($0.0)	($0.4)	$0.0	$0.0	($0.0)	$0.0	($0.4)	835	418
9	Baker - Broadford	Line	AEP	($0.0)	($0.0)	($0.0)	$0.0	($0.1)	($0.0)	($0.0)	($0.1)	($0.1)	10	74
10	Collier	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.0)	$0.1	$0.1	0	5
11	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.1	$0.2	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	142	3
12	Mount Storm - Pruntytown	Line	AP	($0.6)	($0.7)	($0.0)	$0.2	($0.1)	$0.0	$0.0	($0.1)	$0.0	87	64
13	Kanawha River	Transformer	AEP	($0.1)	($0.2)	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	$0.0	158	11
14	Dutch Fork - Windsor	Line	AP	($0.1)	($0.1)	($0.0)	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	119	3
15	Cloverdale - Lexington	Line	AEP	($0.1)	($0.2)	$0.0	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.0	154	94
21	Cheswick - Logans Ferry	Line	DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0
39	Arsenal - Brunot Island	Line	DLCO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.0	$0.0	11	8
55	Cheswick - Logan's Ferry	Line	DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

Table 7-50 DLCO Control Zone top congestion cost impacts (By facility): January through March year 2009 (See 2009 SOM, Table 7-50)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Sammis - Wylie Ridge	Line	AP	($4.0)	($7.9)	($0.0)	$3.9	($0.1)	$0.5	$0.0	($0.6)	$3.4	615	101
2	AP South	Interface	500	($6.9)	($10.2)	($0.0)	$3.2	($0.4)	$0.3	$0.0	($0.7)	$2.6	1,088	216
3	West	Interface	500	($3.8)	($5.5)	($0.0)	$1.6	($0.1)	$0.0	$0.0	($0.1)	$1.5	380	55
4	Wylie Ridge	Transformer	AP	($8.5)	($12.9)	($0.0)	$4.4	($1.2)	$2.2	$0.0	($3.3)	$1.1	354	335
5	Mount Storm - Pruntytown	Line	AP	($1.9)	($2.8)	($0.0)	$0.9	($0.1)	$0.1	$0.0	($0.1)	$0.8	455	17
6	East Frankfort - Crete	Line	ComEd	$0.5	$0.8	$0.0	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	912	0
7	Cloverdale - Lexington	Line	AEP	($0.6)	($1.0)	$0.0	$0.4	($0.1)	$0.0	($0.0)	($0.1)	$0.3	571	220
8	Kammer	Transformer	500	($1.4)	($1.9)	$0.0	$0.5	($0.3)	$0.0	($0.0)	($0.3)	$0.2	1,021	504
9	Beaver - Clinton	Line	DLCO	$0.0	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	11	0
10	Krendale - Seneca	Line	AP	($0.5)	($0.7)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	158	0
11	Ruth - Turner	Line	AEP	($0.4)	($0.6)	$0.0	$0.2	($0.1)	$0.0	($0.0)	($0.1)	$0.2	514	245
12	Mount Storm	Transformer	AP	($0.4)	($0.6)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.1)	$0.2	80	22
13	Bedington - Black Oak	Interface	500	($0.4)	($0.5)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.1)	$0.1	58	55
14	Kanawha River - Bradley	Line	AEP	($0.3)	($0.4)	($0.0)	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.1	24	15
15	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.3	$0.4	$0.0	($0.2)	$0.1	$0.0	($0.0)	$0.1	($0.1)	429	270
17	Logans Ferry - Universal	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.1	20	14
50	Beaver - Mansfield	Line	DLCO	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0
65	Collier	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
188	Crescent	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	1

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-51 Dominion Control Zone top congestion cost impacts (By facility): January through March 2010 (See 2009 SOM, Table 7-51)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$44.1	($13.3)	($0.1)	$57.3	$2.5	$4.4	$0.2	($1.7)	$55.6	1,255	735
2	AEP-DOM	Interface	500	$15.2	$12.4	$0.6	$3.4	($0.1)	($0.3)	($0.0)	$0.1	$3.5	452	76
3	Bedington - Black Oak	Interface	500	$7.5	$4.8	$0.3	$3.1	$0.0	$0.1	($0.0)	($0.1)	$3.0	519	9
4	5004/5005 Interface	Interface	500	($1.9)	($2.9)	$0.1	$1.1	$0.2	$0.2	$0.0	$0.1	$1.2	806	294
5	Cloverdale - Lexington	Line	AEP	$1.2	$0.5	$0.2	$0.9	($0.2)	($0.5)	($0.3)	($0.0)	$0.8	154	94
6	East Frankfort - Crete	Line	ComEd	$1.8	$1.2	$0.1	$0.7	($0.1)	($0.3)	($0.1)	($0.0)	$0.7	835	418
7	Dickerson - Pleasant View	Line	Pepco	$0.5	$0.0	($0.0)	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	53	3
8	Harrisonburg - Endless Caverns	Line	Dominion	$0.0	($0.5)	($0.0)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	128	0
9	Baker - Broadford	Line	AEP	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.6)	($0.0)	$0.4	$0.4	10	74
10	Inwood - Stonewall	Line	AP	$0.1	($0.1)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	159	0
11	Sammis - Wylie Ridge	Line	AP	$0.6	$0.4	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	305	37
12	Messic Road - Morgan	Line	AP	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	172	0
13	Nipetown - Reid	Line	AP	$0.1	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	($0.0)	$0.2	75	18
14	Millville - Old Chapel	Line	AP	$0.0	($0.2)	($0.0)	$0.2	$0.0	$0.0	$0.0	($0.0)	$0.2	41	6
15	Crozet - Dooms	Line	Dominion	$0.1	($0.1)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	3	0
17	Fredericksburg	Transformer	Dominion	($0.0)	($0.3)	($0.0)	$0.3	($0.0)	$0.1	($0.0)	($0.1)	$0.2	29	53
20	Endless Caverns	Transformer	Dominion	($0.0)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	75	0
21	Bristers - Ox	Line	Dominion	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	2	4
22	Edinburg	Transformer	Dominion	$0.1	($0.0)	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	30	1
25	Hollymead - Cash's Corner	Line	Dominion	$0.0	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	5	0

Table 7-52 Dominion Control Zone top congestion cost impacts (By facility): January through March 2009 (See 2009 SOM, Table 7-52)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$14.5	($16.1)	($0.1)	$30.6	$1.2	($0.6)	$0.2	$2.0	$32.6	1,088	216
2	Cloverdale - Lexington	Line	AEP	$5.0	$2.2	$0.7	$3.6	($0.0)	($1.6)	($0.8)	$0.8	$4.4	571	220
3	Kammer	Transformer	500	$3.9	$3.3	$0.8	$1.4	$0.1	($0.5)	($0.8)	($0.2)	$1.1	1,021	504
4	Wylie Ridge	Transformer	AP	$2.5	$1.7	$0.4	$1.2	($0.1)	($0.2)	($0.4)	($0.2)	$1.0	354	335
5	West	Interface	500	($2.3)	($3.3)	$0.0	$1.0	$0.0	$0.1	$0.0	($0.1)	$0.9	380	55
6	Crozet - Dooms	Line	Dominion	$0.6	($0.3)	$0.0	$0.9	($0.3)	($0.2)	($0.0)	($0.1)	$0.8	48	26
7	Mount Storm	Transformer	AP	$1.0	$0.2	$0.1	$0.9	($0.0)	($0.1)	($0.1)	($0.1)	$0.8	80	22
8	Clover - Farmville	Line	Dominion	($0.0)	($0.7)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	41	0
9	Sammis - Wylie Ridge	Line	AP	$1.1	$0.7	$0.2	$0.6	$0.0	($0.1)	($0.1)	$0.1	$0.7	615	101
10	Mount Storm - Pruntytown	Line	AP	$4.8	$4.6	$0.6	$0.8	$0.0	($0.0)	($0.3)	($0.3)	$0.5	455	17
11	5004/5005 Interface	Interface	500	($0.3)	($0.6)	$0.1	$0.4	$0.1	$0.0	($0.0)	$0.0	$0.4	256	191
12	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.5	$0.3	$0.0	$0.2	($0.1)	($0.3)	($0.1)	$0.2	$0.4	429	270
13	East Frankfort - Crete	Line	ComEd	$0.8	$0.5	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	912	0
14	AEP-DOM	Interface	500	$0.5	$0.4	$0.1	$0.1	($0.1)	($0.5)	($0.1)	$0.2	$0.3	96	56
15	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.2	$0.0	($0.0)	$0.1	($0.1)	($0.3)	($0.0)	$0.2	$0.3	62	81
17	Crozet - Barracks Rd	Line	Dominion	$0.1	($0.1)	($0.0)	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	0	1
21	Cranes Corner - Fredericksburg	Line	Dominion	$0.0	$0.0	$0.0	$0.0	$0.1	$0.3	$0.1	($0.1)	($0.1)	0	26
27	Clubhouse - Freeman	Line	Dominion	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	29	0
28	Beechwood - Kerr Dam	Line	Dominion	$0.1	($0.1)	$0.0	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.1	50	39
32	Dayton - Harrisonburg	Line	Dominion	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1	0

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that transmission service customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

In PJM, FTRs have been available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998. Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[1] Since the introduction of this auction, FTRs have been available to all transmission service customers and PJM members. Network service and firm point-to-point transmission service customers can take allocated ARRs or the underlying FTRs through a self scheduling process. On June 1, 2007, PJM implemented marginal losses in the calculation of LMP. Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs.

Firm transmission service customers have access to ARRs/FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission service customers receive requested ARRs/FTRs to the extent that they are consistent both with the physical capability of the transmission system and with ARR/FTR requests of other eligible customers.

The *2010 Quarterly State of the Market Report for PJM: January through March* focuses on the Monthly Balance of Planning Period FTR Auctions during the 2009 to 2010 FTR/ARR planning period. The 2009 to 2010 planning period covers June 1, 2009, through May 31, 2010.

1 87 FERC ¶ 61,054 (1999).

Overview

Financial Transmission Rights

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any residual transmission capability. PJM also runs a Long Term FTR Auction for the three consecutive planning years immediately following the planning year during which the Long Term FTR Auction is conducted. The first Long Term FTR Auction was conducted during the 2008 to 2009 planning period and covers three consecutive planning periods between 2009 and 2012. The second Long Term FTR Auction was conducted during the 2009 to 2010 planning period and covers three consecutive planning periods between 2010 and 2013. In addition, PJM administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. FTR options are not available in the Long Term FTR Auction. For each time period, there are three FTR products: 24-hour, on peak and off peak. FTRs have terms varying from one month to three years. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and the numerous combinations of FTRs. Market participants can also sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the first ten months (June 2009 through March 2010) of the 2009 to 2010 planning period, there were 2,567,353 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the Monthly Balance of Planning Period FTR Auctions for the first ten months (June 2009 through March 2010) of the 2009 to 2010 planning period, total FTR buy bids were 7,354,546 MW.

- **FTR Credit Issues.** There were no participants that defaulted during the first three months of 2010.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2009 to 2010 Annual FTR Auction was low to moderate for FTR obligations and high for FTR options. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction. In order to provide additional information about the ownership of prevailing flow and counter flow FTRs, the Market Monitoring Unit (MMU) categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. Financial entities own 69 percent of prevailing flow and 84 percent of counter flow Monthly Balance of Planning Period FTRs for the first three months of 2010. Overall, financial entities own 76 percent of all Monthly Balance of Planning Period FTRs during the same time period.

Market Performance

- **Volume.** For the first ten months of the 2009 to 2010 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 820,498 MW (11.2 percent) of FTR buy bids and 229,394 MW (9.0 percent) of FTR sell offers.

- **Price.** The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first three months of 2010 was $0.15 per MWh.

- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $17.9 million in net revenue for all FTRs during the first ten months of the 2009 to 2010 planning period.

- **Revenue Adequacy.** FTRs were 100 percent revenue adequate for the 2008 to 2009 planning period. FTRs were paid at 98.7 percent of the target allocation level for the first ten months of the 2009 to 2010 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $748 million of FTR revenues during the first ten months of the 2009 to 2010 planning period and $1,743.8 million during the 2008 to 2009 planning period. For the first ten months of the 2009 to 2010 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Mount Storm aggregate. For the first ten months of the 2009 to 2010 planning period, the top sink and top source with the largest negative FTR target allocations was the Western Hub.

Auction Revenue Rights

Market Structure

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. There were 16,933 MW of ARRs associated with approximately $329,600 per MW-day of revenue that were reassigned in the first ten months of the 2009 to 2010 planning period. There were 15,326 MW of ARRs associated with approximately $533,900 per MW-day of revenue that were reassigned for the full 2008 to 2009 planning period.

Market Performance

- **Revenue Adequacy.** During the 2009 to 2010 planning period, ARR holders will receive $1,273.5 million in ARR credits, with an average hourly ARR credit of $1.33 per MWh. During the 2009 to 2010 planning period, the ARR target allocations were $1,273.5 million while PJM collected $1,347.7 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through March 2010, making ARRs revenue adequate. During the 2008 to 2009 planning period, ARR holders received $2,361.3 million in ARR credits, with an average hourly ARR credit of $2.41 per MWh. For the 2008 to 2009 planning period, the ARR target allocations were $2,361.3 million while PJM collected $2,489.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARRs and FTRs as a Hedge against Congestion.** The effectiveness of ARRs and FTRs as a hedge against actual congestion can be measured several ways. The first is to compare the revenue received by ARR holders to the congestion costs experienced by these ARR holders. The second is to compare the congestion revenue received by FTR holders to the costs of those FTRs. The final and comprehensive method is to compare the revenue received by all ARR and FTR holders to total actual congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. For the 2008 to 2009 planning period, all ARRs and FTRs hedged more than 100 percent of the congestion costs within PJM. During the first ten months of the 2009 to 2010 planning period, total ARR and FTR revenues hedged 95.4 percent of the congestion costs within PJM.

- **ARRs and FTRs as a Hedge against Total Energy Costs.** The hedge provided by ARRs can also be measured by comparing the value of the ARR and self-scheduled FTRs that sink in a zone to the cost of real time energy in the zone. This is a measure of the value of the hedge against real time energy costs provided by ARRs received by loads during this period. The total value of ARRs was 4.3 percent of the total real time energy charges for January through March of 2010. The hedge provided by FTRs can also be measured by comparing the value of the FTRs that sink in a zone to the cost of real time energy in the zone. The total net value of FTRs was -0.1 percent of the total real time energy charges for January through March 2010 because the purchase cost exceeded the value of the credits. When combined, the sum is a measure of the total value of ARRs plus FTRs. The total value of ARRs plus FTRs was 4.2 percent of the total real time energy charges for January through March 2010.

Conclusion

The annual ARR allocation and the FTR auctions provide market participants with hedging instruments. These instruments can be used for hedging positions or for speculation. The Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR auction results for the 2009 to 2010 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs.

FTRs were paid at 98.7 percent of the target allocation level for the first ten months of the 2009 to 2010 planning period. Revenue adequacy for a planning period is not final until the end of the period.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased. The adequacy of FTRs as a hedge against congestion compares FTR revenues to the costs of purchasing the FTRs.

The total of ARR and FTR revenues hedged 95.4 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first ten months of the 2009 to 2010 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of ARR and FTR holders, their revenues or those paying congestion.

Financial Transmission Rights

Patterns of Ownership

Table 8-1 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through March 2010 (See 2009 SOM, Table 8-5)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	31.5%	16.2%	24.5%
Financial	68.5%	83.8%	75.5%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-2 Monthly Balance of Planning Period FTR Auction market volume: January through March 2010 (See 2009 SOM, Table 8-9)

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-10	Obligations	Buy bids	156,274	716,812	79,724	11.1%	637,088	88.9%
		Sell offers	46,206	165,858	11,224	6.8%	154,635	93.2%
	Options	Buy bids	391	11,953	1,621	13.6%	10,332	86.4%
		Sell offers	1,579	33,020	5,686	17.2%	27,334	82.8%
Feb-10	Obligations	Buy bids	129,946	656,279	78,354	11.9%	577,925	88.1%
		Sell offers	40,605	146,757	10,364	7.1%	136,393	92.9%
	Options	Buy bids	622	13,993	1,119	8.0%	12,874	92.0%
		Sell offers	1,702	33,125	6,955	21.0%	26,170	79.0%
Mar-10	Obligations	Buy bids	120,727	607,270	90,189	14.9%	517,081	85.1%
		Sell offers	56,858	201,797	12,542	6.2%	189,255	93.8%
	Options	Buy bids	331	8,420	749	8.9%	7,672	91.1%
		Sell offers	1,224	23,960	5,326	22.2%	18,634	77.8%
2008/2009*	Obligations	Buy bids	2,143,034	9,449,644	782,007	8.3%	8,667,637	91.7%
		Sell offers	504,152	1,991,496	226,544	11.4%	1,764,952	88.6%
	Options	Buy bids	11,754	773,793	22,209	2.9%	751,584	97.1%
		Sell offers	6,550	180,904	32,203	17.8%	148,701	82.2%
2009/2010**	Obligations	Buy bids	1,721,619	7,146,995	803,994	11.2%	6,343,001	88.8%
		Sell offers	602,251	2,135,525	163,581	7.7%	1,971,944	92.3%
	Options	Buy bids	4,323	207,551	16,504	8.0%	191,047	92.0%
		Sell offers	27,725	431,828	65,813	15.2%	366,015	84.8%

* Shows Twelve Months for 2008/2009; ** Shows ten months ended 31-Mar-2010 for 2009/2010

Table 8-3 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January through March 2010 (See 2009 SOM, Table 8-10)

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-10	Bid	393,426	127,235	90,338				117,766	728,765
	Cleared	55,052	10,039	5,963				10,290	81,345
Feb-10	Bid	363,548	100,591	91,281				114,853	670,272
	Cleared	53,791	9,948	6,304				9,430	79,473
Mar-10	Bid	374,155	108,329	106,100				27,107	615,690
	Cleared	66,677	10,555	9,864				3,842	90,938

Table 8-4 Secondary bilateral FTR market volume and weighted-average cleared prices (Dollars per MWh): Planning periods 2008 to 2009 and 2009 to 2010[2] (See 2009 SOM, Table 8-11)

Planning Period	Hedge Type	Class Type	Volume (MW)	Price
2008/2009	Obligation	24-Hour	800	$0.46
		On Peak	1,133	$1.14
		Off Peak	9	$0.84
		Total	1,942	$0.59
	Option	24-Hour	0	NA
		On Peak	6	$6.25
		Off Peak	0	NA
		Total	6	$6.25
2009/2010*	Obligation	24-Hour	1,468	$0.38
		On Peak	317	($0.02)
		Off Peak	432	($0.22)
		Total	2,217	$0.35
	Option	24-Hour	30	$5.93
		On Peak	0	NA
		Off Peak	0	NA
		Total	30	$5.93

* Shows ten months ended 31-Mar-2010

2 The 2009 to 2010 planning period covers the 2009 to 2010 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through the March 2010 FTR Auction.

Price

Table 8-5 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): January through March 2010 (See 2009 SOM, Table 8-14)

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-10	$0.08	$0.18	$0.24				$0.16	$0.13
Feb-10	$0.10	$0.28	$0.21				$0.31	$0.19
Mar-10	$0.11	$0.25	$0.17				($0.07)	$0.15

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 8-6 Monthly Balance of Planning Period FTR Auction revenue: January through March 2010 (See 2009 SOM, Table 8-17)

Monthly Auction	Hedge Type	Trade Type	Class Type 24-Hour	On Peak	Off Peak	All
Jan-10	Obligations	Buy bids	($358,507)	$3,027,607	$1,763,504	$4,432,604
		Sell offers	$383,960	$1,556,699	$561,863	$2,502,522
	Options	Buy bids	$0	$341,524	$118,211	$459,735
		Sell offers	$83,413	$542,599	$261,153	$887,164
Feb-10	Obligations	Buy bids	$530,509	$2,872,273	$2,657,432	$6,060,214
		Sell offers	($116,080)	$1,524,315	$1,983,143	$3,391,378
	Options	Buy bids	$0	$241,692	$234,325	$476,018
		Sell offers	$8,606	$825,079	$709,563	$1,543,248
Mar-10	Obligations	Buy bids	($549,382)	$4,005,065	$2,109,386	$5,565,069
		Sell offers	$565,634	$1,299,894	$578,118	$2,443,646
	Options	Buy bids	$972	$27,948	$25,433	$54,353
		Sell offers	$80,862	$900,428	$434,215	$1,415,505
2008/2009*	Obligations	Buy bids	$18,536,366	$62,983,127	$39,113,790	$120,633,283
		Sell offers	$10,238,514	$20,746,786	$12,003,977	$42,989,277
	Options	Buy bids	$164,213	$5,175,296	$2,995,811	$8,335,320
		Sell offers	$26,515	$13,614,983	$5,286,634	$18,928,133
2009/2010**	Obligations	Buy bids	$508,680	$43,029,578	$30,936,289	$74,474,547
		Sell offers	$3,453,287	$21,358,299	$16,742,654	$41,554,240
	Options	Buy bids	$98,620	$1,870,502	$825,142	$2,794,264
		Sell offers	$262,626	$10,611,834	$6,908,592	$17,783,052

* Shows Twelve Months for 2008/2009; ** Shows ten months ended 31-Mar-2010 for 2009/2010

Figure 8-1 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 through March 31, 2010 (See 2009 SOM, Figure 8-7)

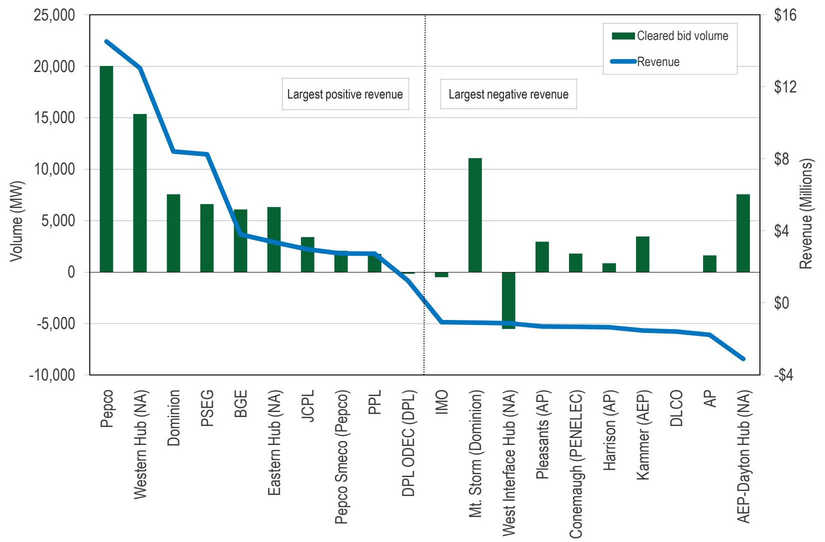
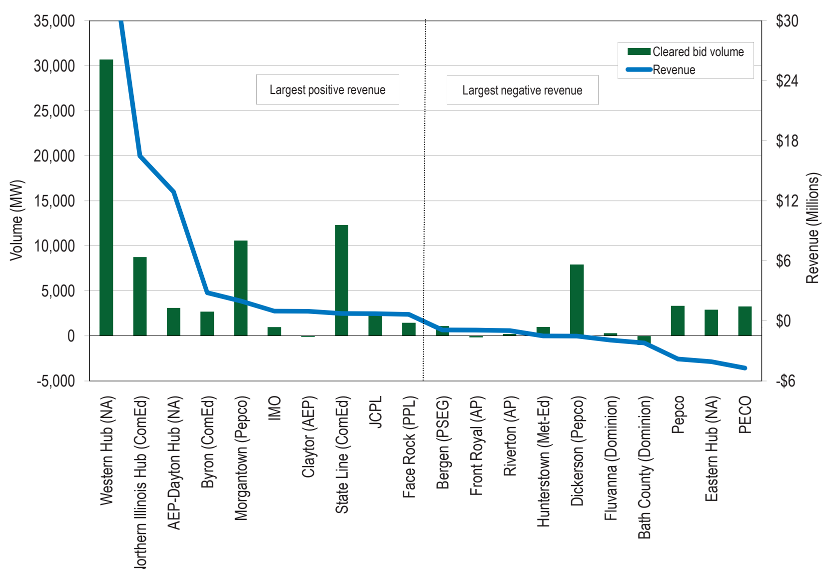


Figure 8-2 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 through March 31, 2010 (See 2009 SOM, Figure 8-8)



Revenue Adequacy

Table 8-7 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010 through March 31, 2010 (See 2009 SOM, Table 8-18)

Accounting Element	2008/2009	2009/2010*
ARR information		
ARR target allocations	$2,361.3	$1,063.5
FTR auction revenue	$2,489.6	$1,138.8
ARR excess	$128.3	$75.3
FTR targets		
FTR target allocations	$1,747.9	$758.3
Adjustments:		
Adjustments to FTR target allocations	($4.1)	($0.7)
Total FTR targets	$1,743.8	$757.6
FTR revenues		
ARR excess	$128.3	$75.3
Competing uses	$0.7	$0.0
Congestions		
Net Negative Congestion (enter as negative)	($59.0)	($33.3)
Hourly congestion revenue	$1,735.7	$739.3
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($52.3)	($31.5)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	($3.1)	($1.8)
Adjustments:		
Excess revenues carried forward into future months	$36.8	$23.5
Excess revenues distributed back to previous months	$16.1	$9.4
Other adjustments to FTR revenues	($2.0)	$0.2
Total FTR revenues	$1,801.2	$780.2
Excess revenues distributed to other months	($30.0)	($41.3)
Excess revenues distributed to CEPSW for end-of-year distribution	$0.5	$0.0
Excess revenues distributed to FTR holders	$4.0	$0.0
Total FTR congestion credits	$1,743.8	$748.0
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,751.4	$740.7
Remaining deficiency	$0.0	$9.6

* Shows ten months ended 31-Mar-10

Table 8-8 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2009 to 2010 through March 31, 2010 (See 2009 SOM, Table 8-19)

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Credits Deficiency (with adjustments)	Credits Excess (with adjustments)
Jun-09	$54.6	$43.9	100%	$43.9	100%	$0.0	$10.6
Jul-09	$53.2	$40.4	100%	$40.4	100%	$0.0	$12.8
Aug-09	$92.4	$92.4	81.3%	$92.4	100.0%	$0.0	$0.0
Sep-09	$31.3	$31.4	87.4%	$31.3	99.9%	$0.0	$0.0
Oct-09	$57.7	$57.8	83.4%	$57.7	99.9%	$0.1	$0.0
Nov-09	$38.2	$37.9	100%	$37.9	100%	$0.0	$0.3
Dec-09	$101.9	$93.7	100%	$93.7	100%	$0.0	$8.2
Jan-10	$221.5	$213.0	100%	$213.0	100%	$0.0	$8.5
Feb-10	$111.8	$110.9	100%	$110.9	100%	$0.0	$0.9
Mar-10	$26.7	$36.1	73.9%	$26.7	73.9%	$9.4	$0.0
Summary for Planning Period 2009 to 2010 through Mar 31, 2010							
Total	$789.4	$757.6	96.0%	$748.0	98.7%	$9.6	$41.4

Figure 8-3 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2009 to 2010 through March 31, 2010 (See 2009 SOM, Figure 8-9)

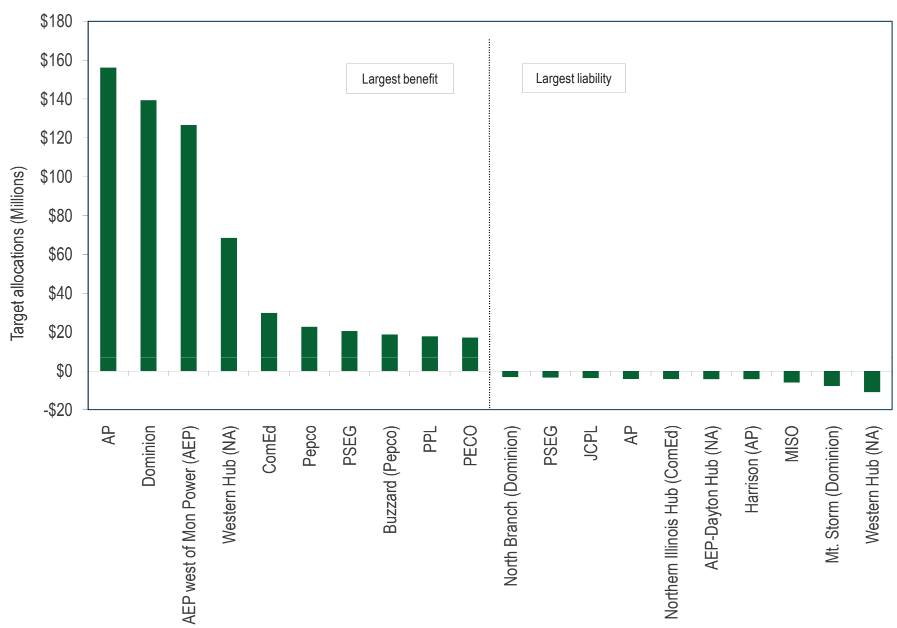
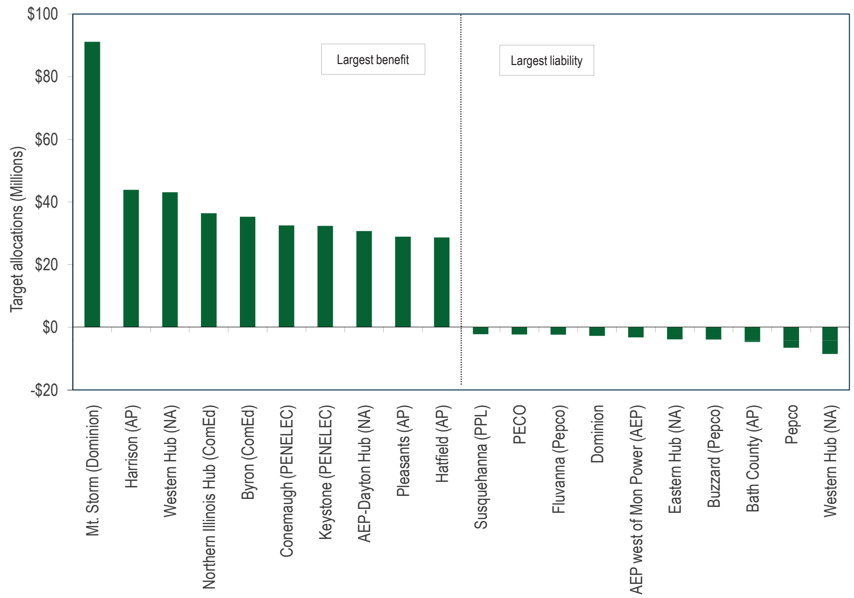


Figure 8-4 Ten largest positive and negative FTR target allocations summed by source: Planning period 2009 to 2010 through March 31, 2010 (See 2009 SOM, Figure 8-10)



Auction Revenue Rights

Market Structure

ARR Reassignment for Retail Load Switching

Table 8-9 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2008, through March 31, 2010 (See 2009 SOM, Table 8-22)

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2008/2009 (12 months)	2009/2010 (10 months)*	2008/2009 (12 months)	2009/2010 (10 months)*
AECO	501	363	$16.1	$6.6
AEP	11	251	$0.2	$5.9
AP	707	578	$164.7	$70.6
BGE	3,361	2,886	$124.3	$60.7
ComEd	3,074	2,354	$10.0	$7.7
DAY	1	3	$0.0	$0.0
DLCO	471	313	$2.1	$0.8
Dominion	5	0	$0.4	$0.0
DPL	1,404	859	$24.8	$9.9
JCPL	1,094	1,050	$45.0	$16.1
Met-Ed	0	10	$0.0	$0.2
PECO	47	25	$1.4	$0.4
PENELEC	0	1	$0.0	$0.0
Pepco	3,040	2,404	$79.9	$24.5
PPL	35	4,001	$2.2	$81.6
PSEG	1,537	1,780	$62.7	$44.6
RECO	40	56	$0.0	$0.0
Total	15,326	16,933	$533.9	$329.6

* Through 31-Mar-10

Market Performance

Revenue Adequacy

Table 8-10 ARR revenue adequacy (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010 through March 31, 2010 (See 2009 SOM, Table 8-24)

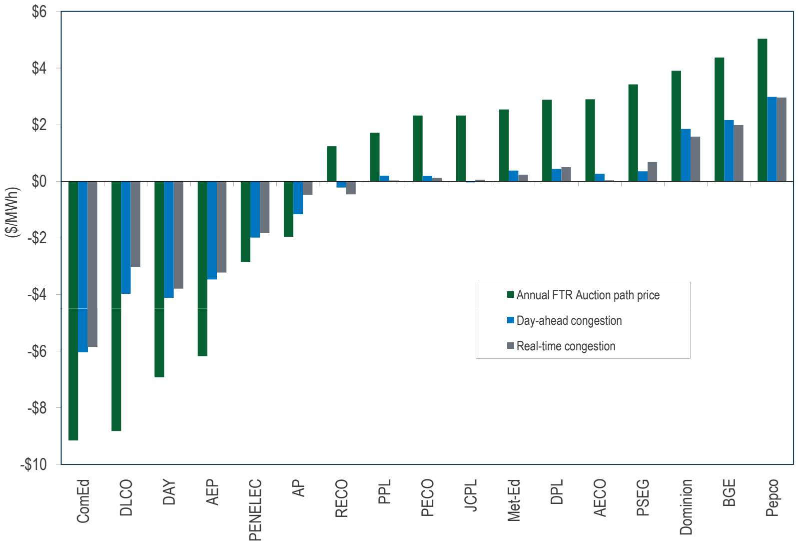
	2008/2009	2009/2010
Total FTR auction net revenue	$2,489.6	$1,347.7
Annual FTR Auction net revenue	$2,422.6	$1,329.8
Monthly Balance of Planning Period FTR Auction net revenue*	$67.1	$17.9
ARR target allocations	$2,361.3	$1,273.5
ARR credits	$2,361.3	$1,273.5
Surplus auction revenue	$128.3	$74.2
ARR payout ratio	100%	100%
FTR payout ratio*	100%	98.7%

* Shows twelve months for 2008/2009 and ten months ended 31-Mar-10 for 2009/2010

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

Figure 8-5 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2009 to 2010 through March 31, 2010 (See 2009 SOM, Figure 8-11)



Effectiveness of ARRs as a Hedge against Congestion

Table 8-11 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2009 to 2010 through March 31, 2010 (See 2009 SOM, Table 8-25)

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$16,334,067	$478,087	$16,812,154	$14,254,944	$2,557,211	>100%
AEP	$4,284,698	$136,272,591	$140,557,289	$111,039,840	$29,517,448	>100%
AP	$45,451,856	$153,439,180	$198,891,036	$34,308,559	$164,582,478	>100%
BGE	$46,459,694	$2,412,695	$48,872,389	$8,075,028	$40,797,361	>100%
ComEd	$14,549,758	$27,411,278	$41,961,036	$57,389,036	($15,428,000)	73.1%
DAY	$6,207,117	$694,003	$6,901,120	$8,811,925	($1,910,805)	78.3%
DLCO	$2,450,918	$2,590	$2,453,508	$15,543,877	($13,090,369)	15.8%
Dominion	$16,378,603	$582,120	$16,960,723	$59,003,126	($42,042,404)	28.7%
DPL	$6,134,065	$128,646,834	$134,780,899	$23,750,400	$111,030,499	>100%
JCPL	$28,119,166	$618,029	$28,737,195	$17,883,647	$10,853,548	>100%
Met-Ed	$108,900	$10,117,104	$10,226,004	$16,715,798	($6,489,794)	61.2%
PECO	$1,932,121	$15,433,133	$17,365,254	($17,681,467)	$35,046,721	>100%
PENELEC	$22,966,832	$10,024,230	$32,991,062	$6,877,739	$26,113,322	>100%
Pepco	$21,798,040	$1,519,724	$23,317,764	$119,042,072	($95,724,307)	19.6%
PJM	$7,727,385	($221,030)	$7,506,355	$2,052,914	$5,453,440	>100%
PPL	$1,102,352	$12,626,294	$13,728,646	($20,897,808)	$34,626,454	>100%
PSEG	$83,906,675	$2,838,461	$86,745,136	$7,213,580	$79,531,556	>100%
RECO	($41,455)	$0	($41,455)	$1,062,447	($1,103,902)	0%
Total	$325,870,792	$502,895,322	$828,766,114	$464,445,658	$364,320,456	>100%

Effectiveness of FTRs as a Hedge against Congestion

Table 8-12 FTR congestion hedging by control zone: Planning period 2009 to 2010 through March 31, 2010 (See 2009 SOM, Table 8-26)

Control Zone	FTR Direction	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference	Percent Hedged
AECO	Counter Flow	($466,207)	($2,048,023)	$1,581,815			
	Prevailing Flow	$3,298,247	$26,456,746	($23,158,499)			
	Total	$2,832,040	$24,408,723	($21,576,684)	$10,318,701	($31,895,385)	<0%
AEP	Counter Flow	($13,733,225)	($34,371,200)	$20,637,976			
	Prevailing Flow	$163,886,461	$252,699,178	($88,812,717)			
	Total	$150,153,236	$218,327,978	($68,174,741)	$99,504,023	($167,678,764)	<0%
AP	Counter Flow	($15,300,411)	($25,489,099)	$10,188,688			
	Prevailing Flow	$171,237,624	$353,932,439	($182,694,815)			
	Total	$155,937,213	$328,443,340	($172,506,127)	$109,671,005	($282,177,132)	<0%
BGE	Counter Flow	$439,502	($3,658,364)	$4,097,866			
	Prevailing Flow	$25,886,653	$39,404,285	($13,517,632)			
	Total	$26,326,155	$35,745,921	($9,419,766)	$34,437,644	($43,857,410)	<0%
ComEd	Counter Flow	($6,419,364)	($24,863,904)	$18,444,540			
	Prevailing Flow	$61,344,346	$39,367,123	$21,977,223			
	Total	$54,924,981	$14,503,219	$40,421,762	$168,552,549	($128,130,787)	24.0%
DAY	Counter Flow	($1,391,971)	($3,215,677)	$1,823,706			
	Prevailing Flow	$2,372,577	$3,280,851	($908,274)			
	Total	$980,606	$65,174	$915,432	$6,886,013	($5,970,581)	13.3%
DLCO	Counter Flow	$981,678	($6,387,470)	$7,369,148			
	Prevailing Flow	$6,471,734	$3,436,568	$3,035,166			
	Total	$7,453,412	($2,950,902)	$10,404,314	$19,574,696	($9,170,382)	53.2%
Dominion	Counter Flow	($11,913,130)	($22,259,968)	$10,346,838			
	Prevailing Flow	$150,326,174	$256,143,876	($105,817,702)			
	Total	$138,413,044	$233,883,908	($95,470,863)	$130,960,141	($226,431,005)	<0%
DPL	Counter Flow	($1,112,356)	($3,392,889)	$2,280,533			
	Prevailing Flow	$11,459,884	$38,328,850	($26,868,966)			
	Total	$10,347,528	$34,935,961	($24,588,434)	$24,322,116	($48,910,550)	<0%
JCPL	Counter Flow	($1,751,686)	($4,548,043)	$2,796,357			
	Prevailing Flow	$2,833,192	$47,925,758	($45,092,566)			
	Total	$1,081,506	$43,377,715	($42,296,209)	$16,499,984	($58,796,193)	<0%
Met-Ed	Counter Flow	($1,228,120)	($2,364,750)	$1,136,630			
	Prevailing Flow	$14,761,443	$35,530,562	($20,769,118)			
	Total	$13,533,323	$33,165,811	($19,632,488)	$4,591,610	($24,224,098)	<0%
PECO	Counter Flow	($295,703)	($2,586,346)	$2,290,643			
	Prevailing Flow	$18,681,961	$58,228,070	($39,546,109)			
	Total	$18,386,258	$55,641,724	($37,255,466)	($19,416,128)	($17,839,338)	<0%
PENELEC	Counter Flow	($12,165,566)	($33,063,348)	$20,897,782			
	Prevailing Flow	$56,207,665	$102,842,955	($46,635,290)			
	Total	$44,042,099	$69,779,608	($25,737,508)	$50,436,928	($76,174,436)	<0%

Table 8-12 FTR congestion hedging by control zone: Planning period 2009 to 2010 through March 31, 2010 (continued)

Control Zone	FTR Direction	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference	Percent Hedged
Pepco	Counter Flow	$2,666,503	($17,633,696)	$20,300,200			
	Prevailing Flow	$89,751,780	$109,276,645	($19,524,866)			
	Total	$92,418,283	$91,642,949	$775,334	$55,472,078	($54,696,745)	1.4%
PJM	Counter Flow	($6,800,989)	($10,386,715)	$3,585,725			
	Prevailing Flow	$1,948,326	$6,277,186	($4,328,860)			
	Total	($4,852,663)	($4,109,529)	($743,135)	$5,268,874	($6,012,009)	<0%
PPL	Counter Flow	($410,746)	($8,497,541)	$8,086,795			
	Prevailing Flow	$20,017,607	$69,545,831	($49,528,224)			
	Total	$19,606,861	$61,048,290	($41,441,429)	($8,224,646)	($33,216,783)	<0%
PSEG	Counter Flow	$614,578	($9,801,506)	$10,416,085			
	Prevailing Flow	$27,011,465	$122,447,111	($95,435,646)			
	Total	$27,626,043	$112,645,604	($85,019,561)	($4,131,448)	($80,888,113)	<0%
RECO	Counter Flow	($894,840)	($4,288,883)	$3,394,043			
	Prevailing Flow	($9,397)	$1,463,565	($1,472,961)			
	Total	($904,236)	($2,825,318)	$1,921,082	$1,181,661	$739,421	162.6%
Total	Counter Flow	($69,182,052)	($218,857,424)	$149,675,372			
	Prevailing Flow	$827,487,742	$1,566,587,601	($739,099,859)			
	Total	$758,305,690	$1,347,730,177	($589,424,487)	$705,905,799	($2,163,536,265)	<0%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-13 ARR and FTR congestion hedging by control zone: Planning period 2009 to 2010 through March 31, 2010 (See 2009 SOM, Table 8-27)

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$19,253,322	$2,796,356	$24,408,723	($2,359,045)	$10,759,638	($13,118,683)	<0%
AEP	$223,262,229	$148,261,305	$218,327,978	$153,195,556	$112,625,849	$40,569,707	>100%
AP	$365,048,488	$153,972,404	$328,443,340	$190,577,552	$121,818,986	$68,758,566	>100%
BGE	$52,131,739	$25,994,445	$35,745,921	$42,380,263	$36,666,433	$5,713,830	>100%
ComEd	$27,261,279	$54,232,926	$14,503,219	$66,990,986	$182,854,782	($115,863,796)	36.6%
DAY	$7,505,314	$968,250	$65,174	$8,408,390	$7,112,757	$1,295,633	>100%
DLCO	$2,454,337	$7,359,499	($2,950,902)	$12,764,738	$21,637,065	($8,872,327)	59.0%
Dominion	$213,840,239	$136,669,040	$233,883,908	$116,625,371	$140,301,742	($23,676,371)	83.1%
DPL	$17,792,090	$10,217,149	$34,935,961	($6,926,722)	$25,877,414	($32,804,136)	<0%
JCPL	$34,924,192	$1,067,879	$43,377,715	($7,385,644)	$17,160,629	($24,546,273)	<0%
Met-Ed	$27,312,021	$13,362,803	$33,165,811	$7,509,013	$3,926,483	$3,582,530	>100%
PECO	$49,863,646	$18,154,591	$55,641,724	$12,376,513	($21,255,273)	$33,631,786	>100%
PENELEC	$49,412,326	$43,487,169	$69,779,608	$23,119,887	$51,562,058	($28,442,171)	44.8%
Pepco	$23,702,306	$91,253,813	$91,642,949	$23,313,170	$58,358,119	($35,044,949)	39.9%
PJM	$9,979,482	($4,791,519)	($4,109,529)	$9,297,492	$206,128	$9,091,364	>100%
PPL	$55,143,860	$19,359,815	$61,048,290	$13,455,385	($8,593,791)	$22,049,176	>100%
PSEG	$94,609,270	$27,277,955	$112,645,604	$9,241,621	($2,087,082)	$11,328,703	>100%
RECO	($41,455)	($892,843)	($2,825,318)	$1,891,020	$1,195,304	$695,716	>100%
Total	$1,273,454,685	$748,751,037	$1,347,730,176	$674,475,546	$760,127,241	($85,651,695)	88.7%

Table 8-14 ARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010[3] through March 31, 2010 (See 2009 SOM, Table 8-28)

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2008/2009	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,489,647,665	$130,237,257	>100%
2009/2010*	$1,063,546,925	$748,768,270	$1,138,842,282	$673,472,913	$705,905,799	($32,432,886)	95.4%

* Shows ten months ended 31-Mar-10

ARRs and FTRs as a Hedge against Total Real Time Energy Charges

Table 8-15 ARRs and self-scheduled FTR credits as a hedge against energy charges by control zone: January through March 2010 (See 2009 SOM, Table 8-29)

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and Self-Scheduled FTR Credits
AECO	$4,027,578	$211,761	$4,239,339	$129,305,115	3.3%
AEP	$1,056,501	$76,963,007	$78,019,508	$1,445,329,099	5.4%
AP	$11,207,307	$82,303,141	$93,510,448	$564,957,579	16.6%
BGE	$11,455,815	$1,329,748	$12,785,563	$459,636,511	2.8%
ComEd	$3,587,612	$4,283,276	$7,870,888	$870,669,254	0.9%
DAY	$1,530,522	$652,105	$2,182,627	$174,298,615	1.3%
DLCO	$604,336	$1,251	$605,587	$145,944,219	0.4%
Dominion	$1,512,509	$67,616,236	$69,128,745	$1,299,971,572	5.3%
DPL	$4,038,560	$166,834	$4,205,394	$247,032,448	1.7%
JCPL	$6,933,493	$380,131	$7,313,624	$279,392,614	2.6%
Met-Ed	$26,852	$5,010,971	$5,037,823	$193,405,465	2.6%
PECO	$476,413	$9,168,540	$9,644,954	$508,025,259	1.9%
PENELEC	$5,663,054	$4,863,468	$10,526,523	$196,356,995	5.4%
Pepco	$5,374,859	$526,785	$5,901,644	$424,291,254	1.4%
PJM	$1,905,382	$1,119,212	$3,024,595	NA	NA
PPL	$271,813	$5,522,925	$5,794,738	$523,991,268	1.1%
PSEG	$20,689,317	$1,890,187	$22,579,504	$548,497,065	4.1%
RECO	($10,222)	$0	($10,222)	$16,608,300	(0.1%)
Total	$80,351,702	$262,009,579	$342,361,281	$8,025,091,048	4.3%

3 The FTR credits do not include after-the-fact adjustments. For the 2009 to 2010 planning period, the ARR credits were the total credits allocated to all ARR holders for the first ten months (June 2009 through March 2010) of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the first ten months of this planning period and the portion of Annual FTR Auction revenue distributed in the first ten months.

Table 8-16 FTRs as a hedge against energy charges by control zone: January through March 2010 (See 2009 SOM, Table 8-30)

Control Zone	FTR Credits (Excluding Self-Scheduled FTRs)	FTR Auction Revenue (Excluding Self-Scheduled FTRs)	Total FTR Hedge (Excluding Self-Scheduled FTRs)	Total Energy Charges	Percent of Energy Charges Covered by FTR Credits (Excluding Self-Scheduled FTRs)
AECO	$585,267	$4,801,902	($4,216,635)	$129,305,115	(3.3%)
AEP	$3,586,279	($2,358,323)	$5,944,602	$1,445,329,099	0.4%
AP	($6,223,178)	($692,590)	($5,530,588)	$564,957,579	(1.0%)
BGE	$4,339,219	$7,881,037	($3,541,818)	$459,636,511	(0.8%)
ComEd	$9,137,232	($279,073)	$9,416,305	$870,669,254	1.1%
DAY	($222,418)	($376,109)	$153,691	$174,298,615	0.1%
DLCO	$5,647,424	($1,233,049)	$6,880,473	$145,944,219	4.7%
Dominion	$3,503,946	$7,053,967	($3,550,021)	$1,299,971,572	(0.3%)
DPL	$3,632,585	$8,688,155	($5,055,570)	$247,032,448	(2.0%)
JCPL	$2,789,730	$10,347,198	($7,557,469)	$279,392,614	(2.7%)
Met-Ed	$1,563,792	$1,541,379	$22,413	$193,405,465	0.0%
PECO	$802,196	$2,056,165	($1,253,969)	$508,025,259	(0.2%)
PENELEC	$12,516,379	$11,322,285	$1,194,094	$196,356,995	0.6%
Pepco	$27,539,162	$25,610,061	$1,929,101	$424,291,254	0.5%
PJM	($2,443,711)	($1,920,942)	($522,769)	NA	NA
PPL	$4,389,630	$2,617,969	$1,771,661	$523,991,268	0.3%
PSEG	$22,812,695	$27,024,534	($4,211,839)	$548,497,065	(0.8%)
RECO	($386,137)	($811,086)	$424,949	$16,608,300	2.6%
Total	$93,570,091	$101,273,480	($7,703,389)	$8,025,091,048	(0.1%)

Table 8-17 ARRs and FTRs as a hedge against energy charges by control zone: January through March 2010 (See 2009 SOM, Table 8-31)

Control Zone	ARR Related Hedge (Including Self-Scheduled FTRs)	FTR Hedge (Excluding Self-Scheduled FTRs)	Total ARR and FTR Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and FTR Credits
AECO	$4,239,339	($4,216,635)	$22,704	$129,305,115	0.0%
AEP	$78,019,508	$5,944,602	$83,964,110	$1,445,329,099	5.8%
AP	$93,510,448	($5,530,588)	$87,979,860	$564,957,579	15.6%
BGE	$12,785,563	($3,541,818)	$9,243,746	$459,636,511	2.0%
ComEd	$7,870,888	$9,416,305	$17,287,193	$870,669,254	2.0%
DAY	$2,182,627	$153,691	$2,336,317	$174,298,615	1.3%
DLCO	$605,587	$6,880,473	$7,486,060	$145,944,219	5.1%
Dominion	$69,128,745	($3,550,021)	$65,578,724	$1,299,971,572	5.0%
DPL	$4,205,394	($5,055,570)	($850,176)	$247,032,448	(0.3%)
JCPL	$7,313,624	($7,557,469)	($243,845)	$279,392,614	(0.1%)
Met-Ed	$5,037,823	$22,413	$5,060,236	$193,405,465	2.6%
PECO	$9,644,954	($1,253,969)	$8,390,985	$508,025,259	1.7%
PENELEC	$10,526,523	$1,194,094	$11,720,616	$196,356,995	6.0%
Pepco	$5,901,644	$1,929,101	$7,830,745	$424,291,254	1.8%
PJM	$3,024,595	($522,769)	$2,501,826	NA	NA
PPL	$5,794,738	$1,771,661	$7,566,399	$523,991,268	1.4%
PSEG	$22,579,504	($4,211,839)	$18,367,665	$548,497,065	3.3%
RECO	($10,222)	$424,949	$414,727	$16,608,300	2.5%
Total	$342,361,281	($7,703,389)	$334,657,892	$8,025,091,048	4.2%